REPORT ON

# OIL AND GAS

## FOR THE MINISTER OF FINANCE

Intended use of this document:

*The Davis Tax Committee is advisory in nature and makes recommendations to the Minister of Finance. The Minister will take into account the report and recommendations and will make any appropriate announcements as part of the normal budget and legislative processes.*

*As with all tax policy proposals, these proposals will be subject to the normal consultative processes and Parliamentary oversight once announced by the Minister.*

**THE DAVIS TAX COMMITTEE**

**September 2016**

**Dear Minister**

We, as the Members of the Davis Tax Committee, have the honour and privilege to provide you with this report which has been:

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## Contents

## Abbreviations

| | |
|---|---|
| AETR | Average Effective Tax Rate or Government Take |
| AOE | Additional Oil Entitlement |
| BBBEE | Broad Based Black Economic Empowerment |
| BEE | Black Economic Empowerment |
| BR | Budget Review |
| COGSI | Cape Oil and Gas Supply Initiative |
| CNG | Condensed Natural Gas |
| DMR | Department of Mineral Resources |
| DOE | Department of Energy |
| EIA | US Energy Information Administration |
| EPC | Engineering, Procurement and Construction Contracts |
| FPSO | Floating Production Storage and Offloading vessel |
| FTE | Full-Time Equivalent |
| GDP | Gross Domestic Product |
| GTL | Gas to Liquids |
| HDSA | Historically Disadvantaged South Africans |
| IIAPCO | Independent Indonesian American Petroleum Company |
| IMF | International Monetary Fund |
| IOC | International Oil Company |
| IPAP | Industrial Policy Action Plan |
| IRP | Integrated Resource Plan |
| IRR | Internal rate of return |
| ITA | Income Tax Act, No 58 of 1962(as amended) |
| LNG | Liquified Natural Gas |
| MPRDA | Mineral and Petroleum Resources Development Act 28 of 2002 |
| NDP | National Development Plan |

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|---|---|
| NERSA | National Energy Regulator of South Africa |
| NDP | National Development Plan |
| NGP | New Growth Path |
| NOC | National Oil Company |
| NPV | Net Present Value |
| ONPASA | Onshore Petroleum Association of South Africa |
| OP26 | OP26 prospecting lease, OP26 mining lease and OP26 mining Subleases |
| OPASA | Offshore Petroleum Association of South Africa |
| OPEC | Organisation of the Petroleum Exporting Countries |
| PASA | Petroleum Agency of South Africa |
| PetroSA | The Petroleum Oil and Gas Corporation of SA SOC Ltd |
| PPE | Property, plant and equipment |
| PSA | Production Sharing Agreement |
| PSC | Production Sharing Contract |
| RRT | Resource Rent Tax |
| SA | Service Agreement |
| SAOGA | South African Oil and Gas Alliance |
| SIMS | State intervention in the Mining Sector |
| TCF | Trillion Cubic Feet |
| TCP | Technical Co-operation Permit |
| TOR | Terms of Reference |

## Executive Summary

The South African Oil and Gas industry is still in a nascent stage of development with considerable uncertainty with regard to the size and commercial recoverability of oil and gas reserves both offshore (deep-water) and onshore (shale gas). The contribution of the upstream oil and gas industry to economic growth and job creation is at present insignificant compared with hard-rock mining, with only one large scale producer of offshore gas in South Africa, that secures 1523 direct FTE jobs, an estimated 4569 indirect jobs and an estimated 9138 induced jobs [1]. The oil and gas industry differs from the hard-rock mining in respect of its levels of maturity, geological risk, cost of failure, size and quality of mineral resource deposits, operating environment and operating costs, cost of development, pre-existence of support industries, transportation and commercialisation. Furthermore, South Africa is an unproven hydrocarbon territory, which competes in a global arena with countries that have proven hydrocarbon resources, a financially strong oil and gas sector, high well head prices, low development costs, economic stability and low political risk, and regional market demand to attract foreign direct investment.

The South African Oil and Gas industry may hold the key to the country's energy security challenges, with possible significant resources reported by the US EIA in relation to shale gas in the Karoo, and expectations of hydrocarbon finds in deep-water offshore of South Africa, analogous to our neighbouring countries (and the Falkland Islands). Such significant finds could contribute between 3.3% and 9.6% of South Africa's GDP at 2010 levels, or between 1.1% and 2.8% of projected 2035 GDP levels. In terms of employment, the modelled values represent between 2.7% and 6.5% of 2010's measured employment level, or between 0.98% and 2.4% of the projected level of employment given sustained 4.5% pa growth in GDP to 2035[2].

The Tenth Schedule to the ITA which regulates the taxation of oil and gas companies, encourages exploration and production of oil and gas. The proposed amendments to the Mineral and Petroleum Resources Development Act (MPRDA) with regard to State Participation (a component of Government Take) have, however, created additional policy-induced uncertainty for international investors, discouraging the further progression and uptake of oil and gas rights in South Africa. The Davis Tax Committee recognises that South Africa currently has a well-established and efficient tax

[1] PetroSA, 2015

[2] At page 97 - Econometrix, 2012. Karoo shale gas report: special considerations surrounding potential shale gas resources in the southern Karoo of South Africa. Available at: http://www-static.shell.com/static/zaf/downloads/aboutshell/econometrix/econometrix_report.pdf

system on the whole, so major changes are not necessary. The major deterrents to investment in South Africa are posed by factors outside the tax system. Subject to minor refinements as proposed, the Tenth Schedule is appropriate to attracting oil and gas investors in an environment of geological uncertainty. Accordingly, the Davis Tax committee recommends retention of the existing fiscal regime.

In the event of a significant commercial discovery, the Tenth Schedule stability is limited to safeguarding only the provisions of the Tenth Schedule, and the Royalty stability preserves only the formula used to derive the rate of the royalty paid to the State. The Legislature is therefore not restricted from introducing new taxes, or making amendments to the body of the ITA. The Davis Tax Committee recommends that Government creates fiscal stability for the 'first-mover' companies which face the greatest risks, and deals with the transition to any new tax dispensation by enforcing the relinquishment provisions under the MPRDA which compel the size of a block/field to shrink as the oil and gas project moves through its life stages (for example, the conversion of an exploration right into a production right). Any new tax dispensation will apply prospectively to all new rights issued, including the acreage that is released through the relinquishment process. This provides predictability to the "frontier" investor, confronted by huge geological and commercial risk, which is difficult to quantify *ex-ante,* but still allows policy flexibility to Government once the extent of commercially viable resources can be more accurately scoped.

The Oil and Gas stream of Project Phakisa is focused on the support industries necessary to encourage offshore exploration and production in South Africa. An oil and gas company may diversify its trade, particularly where limited local suppliers exist in the service of the oil and gas industry. Oil and gas companies have had to make investments in support infrastructures such as warehousing, laydown areas, support vessels and emergency vessels e where such services are not available locally, and may lease these support services to each other. As observed by the IMF[3] , 10% of the excess losses may be offset against such non-oil and gas activities. These oil and gas companies would benefit from the ability to offset a small portion of their oil and gas tax assessed losses against their taxable income derived from investments into support industries. The 10% is available each year for the duration of the tax assessed loss from oil and gas activities.

The IMF[4] furthermore states that refining is not a "post-exploration" activity, yet paragraph 5(3) recognises that refining can fall within the scope of an "oil and gas right". This specific inclusion of

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[3] Page 23 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[4] Page 23 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

refining, at paragraph 5(3), is to accommodate the offset of tax losses generated by the uplift of capital expenditure, incurred in the exploration and production of oil and gas, against taxable income from refining. The aim of this specific inclusion is to encourage local beneficiation of South Africa's oil and gas petroleum resources through the refining of indigenous condensate and gas. Imported condensate (and crudes), imported LNG feedstock and imported blend-stocks (used to achieve the liquid fuels specifications in terms of octane requirements) to the refinery will not qualify for the offset of tax losses from exploration and production expenditure in relation to an MPRDA right. The DTC therefore, recommends retention of the 10% assessed loss set-off provision.

Instruments of State Participation have a fiscal effect on the division of revenues even when held by a commercially operating state owned enterprise, and should be regarded as part of the broad fiscal regime in addition to more conventional instruments such as royalties and income taxes. To ensure investor confidence, the mechanics for State Participation should be clarified in the MPRDA and clearly articulated in the Exploration and Production Rights as issued by the DMR.

Contrary to the Interim Mining Report that recommends maintaining the formula based Royalty for the rest of the mining industry, the DTC recommends replacing the variable royalty rate formula with a flat rate Royalty of 5% for oil and gas. Analysis by the IMF has suggested a rate of at least 5% which is considered low in global terms. The royalty formula applicable to the rest of the mining industry is designed to increase the rate of taxation marginally depending on the profitability of the mine. In the context of marginal mines the royalty payable on production, without regard to profitability, may force premature closure of a mine. By contrast, the IMF's economic assessment of South Africa's petroleum fiscal system simulation reflects that when an oil and gas company enters production, the oil and gas company almost immediately begins to pay royalties at the capped maximum rate and continues at this royalty rate for the significant portion of the life of the field. The likely reason is that when economic field size thresholds are applied by oil and gas companies', uneconomic fields are not developed and such fields accordingly never enter production. Accordingly, the variable rate formula in the oil and gas industry introduces unnecessary complexity and should therefore be simplified.

The IMF recommended a depletion allowance in relation to the acquisition of MPRDA rights. The Interim Mining report has reflected an element of sympathy for providing such incentives where taxpayers have obtained such rights on an arm's length basis from a third party, sometimes at a substantial cost. At this stage however the DTC is, subject to detailed investigation, not inclined to recommend an amortisation write-off in respect of the various mineral rights accorded in terms of the MPRDA.  In the context of oil and gas there is a deduction in relation to the consideration paid for an oil and gas right in the form of the participation election at paragraph 8 of the Tenth Schedule.

Section 36(11) of the ITA provides a definition of 'capital expenditure' for hard rock mining purposes. What is, and what is not, 'of a Capital nature' is not defined in the ITA for Tenth Schedule purposes and depends on a complex body of case law. It is recommended that the SARS issue an Interpretation Note to provide further clarity on the classification of "capital expenditure" for purposes of the Tenth Schedule.

As informed by the Wait Study, even if attracting investment in the oil and gas sector does not yield significant tax revenue for the *fiscus* (and contribute substantially toward GDP as a percentage), the multiplier effect of such an investment provides the platform for job creation. The primary advocacy for encouraging exploration and exploitation of South Africa's oil and gas potential is contained in the National Development Plan, which envisages that gas (indigenous or imported Liquified Natural Gas) could make a significant contribution to South Africa's energy security, whilst reducing greenhouse gas emissions and carbon intensity.

In conclusion, in an environment of considerable geological and policy uncertainty and low oil prices, the Davis Tax Committee recommends retention of the existing attractive fiscal regime for oil and gas companies.

## 1. The purpose and objectives of the report.

This report reviews the existing tax regime applicable to oil and natural gas production in South Africa, in the context of the terms of reference of the Davis Tax Committee. Recommendations are made to where changes are appropriate and also what should be left unchanged. The report is confined to the exploitation of naturally occurring oil and gas, and does not consider the taxation of enterprises such as Sasol which convert coal and natural gas into petroleum. On 13 August 2015, the First Interim Report on Mining ('the Mining Report') was released for public comment. The Mining Report may be accessed on the Davis Tax Committee website, [www.taxcom.org.za](http://www.taxcom.org.za).

The extraction of hydrocarbons, particularly natural gas is distinct from hard rock mining in terms of:

- *maturity of the industry* – in the context of South Africa hard rock mining, particularly in the coal and gold sectors, is mature with the location and extent of remaining ore bodies largely known, but there has been limited (deep-water) exploration for oil and gas and, accordingly, the potential of the country's oil and gas resource is relatively unknown and untapped;
- *geological risk* –There is considerable geological risk in the oil and gas sector in South Africa as there is only a 1 in 16 wells drilled chance of commercial discovery (500mbbl field) in the South African oil and gas sector;
- *cost of failure* - in the case of offshore oil and gas, the scale of preproduction expenditure, which includes exploration, tends to be substantially greater than is the case in hard rock mining. The cost of an appraisal program for oil and gas may be USD$980million[5] which makes the cost of failure high in the oil and gas sector;
- *size and quality of mineral resource deposit*s – the size of the ore body and quality of the ore may be quantified with a higher degree of accuracy in hard rock mining than the size of the reservoir and recoverability factor in oil and gas (so-called tight reservoirs);
- *operating environment and operating costs* – hard rock mining is traditionally conducted onshore or in shallow water alluvial deposits. Offshore oil and gas exploration and production is subject to meteorological and oceanographic (met-

[5] Page 40 – IMF,2015

ocean) conditions, offshore deep-water oil and gas operations require costly specialised support infrastructure such as FPSO, offshore platforms and logistics (helicopters and supply vessels);

- *Cost of development* – offshore oil and gas well development costs significantly exceed the development costs of hard-rock mineral resources where the industry development costs in South Africa are USD$5billion per annum[6]. Just one offshore oil and gas well development can cost in the region of USD$2billion to USD$4billion[7].
- *Pre-existence of support industries* – the support industries for hard rock mining are well established and local service providers are available. The bulk of oil and gas capital equipment (for example drill rigs and sub-sea installations) and support services (drill operators etc.) must be imported, as they are not available from local service providers;
- *Transportation* – South Africa already has an established transport infrastructure for hard-rock minerals. The extracted metals and minerals can be transported by truck or rail loading with existing railway and road infrastructure, whereas infrastructure for the transportation of gas must still be developed. Gas can only be transported by pipeline (to be constructed) or with specialised gas compression and regasification vessels (CNG vessels). For mineral resources, the construction cost of port and rail infrastructure can exceed the cost of pipelines;
- *Commercialisation* – there is a ready market for hard rock mineral resources. South Africa does not have a large established gas market. There is only one large scale off-taker for gas, located along the Southern Coastal region of South Africa in the form of the Gas-to-Liquid (GTL) plant operated by PetroSA in Mossel Bay. If gas is utilised for power generation, as envisaged in the NDP, this will change the ability of oil and gas rights holders to commercialise gas reserves off the West Coast of South Africa. The major opportunity for oil and gas is, thus, for feedstock for electricity generation.

For these reasons, the oil and gas industry is addressed in a separate report to the Mining Report.

## 2. The Davis Tax Committee and its Terms of Reference relating to the oil and gas sector.

[6] Page 17 - Ranosek ,2014
[7] Page 40 - IMF, 2015

The mandate of the Davis Tax Committee is to review the tax system with the objective that taxation be structured to promote economic growth, and other objectives such as poverty alleviation, job creation and fiscal stability. Without economic growth it will be difficult for the other objectives to be achieved. Given the important changes in the oil and gas sector and their potential to generate growth, it is appropriate to review the taxation of hydrocarbon producers to ensure that the tax regime promotes, rather than deters, exploration and investment.

The following extract from its Terms of Reference constitutes general guidance to the Committee:

> "… to inquire into the role of the tax system in the promotion of inclusive economic growth, employment creation, development and fiscal sustainability. The Committee will take into account in its work recent domestic and global developments and, in particular, the long term objectives of the National Development Plan (NDP). The Committee should also evaluate the South African tax system against the international tax trends, principles and practices, as well as recent international initiatives to improve tax compliance and deal with tax base erosion. "

In mandating specific areas for attention, the TOR has the following to say about mining:

"As noted in the 2013 Budget Review (BR), the Committee will consider

a) Whether the current mining tax regime is appropriate, taking account of:

- the agreement between Government, Labour and Business to ensure that the mining sector contributes to growth and job creation, remains a competitive investment proposition, and all role players contribute to better working and living conditions; and
- the challenges facing the mining sector, including low commodity prices, rising costs, falling outputs and declining margins, as well as to its current contribution to tax revenues."

In fulfilling its mandate the TOR prescribes the following tax objectives which need to be taken into account:

a) Revenue-raising to fund government expenditure is the primary objective of taxation;

b) Social objectives, building a cohesive and inclusive society can be met partially through a progressive tax system and by raising revenue in order to redistribute resources;

c) Market failures can be corrected by applying a tax on production and/or consumption to internalise negative externalities, e.g. pollution or consumption of harmful products;

d) The tax system can influence behavioural changes by encouraging certain actions (e.g. savings) and discouraging others (e.g. smoking);

e) Taxes and tax incentives are sometimes used in targeted ways to encourage higher levels of investment to help facilitate economic growth;.

f) International competitiveness is important, although the tax system is not the main driver of international competiveness. Innovation and productivity improvements are far more important. We should guard against the 'race to the bottom' in our efforts to strive for a 'competitive tax system' ".

## 3. Criteria for a good oil and gas fiscal system

The global market for oil and gas exploration has evolved to the point that much of the world's surface, with favourable oil and gas potential open to exploitation, has taken on some of the characteristics of a commodity, with bid-rounds for acreage released by governments. Governments compete for capital and technology to develop their hydrocarbon sector. In order to devise and apply the appropriate policies, strategies and tactics, each must assess its position in the global marketplace and evaluate its particular situation, boundary conditions, concerns and objectives. Companies look for investment opportunities that suit their corporate strategies and risk-reward profiles. The initial decision to invest and the resulting allocation of revenue and benefits are greatly influenced by the content of existing legal arrangements and fiscal policies.

The fiscal regime can be used to convert a government's policy into economic signals to the market, and influence investment decisions, provided that the framework is clear, is not changed retroactively, and does not discriminate among the participants. Several countries have used favourable taxation of oil and gas to support the development of the sector in addition to relevant sector reforms. The challenge of an efficient fiscal system is to induce maximum effort from the oil and gas companies, while ensuring that the host government is adequately compensated[8] .

[8] Page 12 – Tordo, 2007

From the government's standpoint, this means the design of a tax system that:

(i) promotes economic growth;

(ii) supports macroeconomic stability by providing predictable and stable tax revenue flows;

(iii) permits capturing a greater share of the revenue during periods of high profits;

(iv) avoids the introduction of distorting effects through the fiscal instruments;

(v) maximizes the present value of revenue receipts by providing for appropriations during the early years of production; and

(vi) is neutral and encourages economic efficiency as a yardstick.

From the investing company's standpoint this means the search for a tax system that provides for:

(i) a minimum number of front-end loaded non-profit-sensitive taxes in order to facilitate recovery of capital before being laden with heavy taxes.(Companies only invest where reasonable IRR is identified);

(ii) the ability to repatriate profits to shareholders in their home countries; and

(iii) an overall policy environment that is transparent, predictable, stable, and based on internationally recognized industry standards and the rule of law, so that decisions can be made with reasonable confidence.

In addition to the above described characteristics, the host government needs to take into consideration its relative position vis-à-vis other countries. In a perfectly competitive world, countries with favourable geologic potential, high wellhead prices, low development costs, and low political risk will tend to offer more stringent fiscal terms than those with less favourable geology, low wellhead prices, high development cost, and high political risk. The economic strength and political stability of the country, oil supply balance, regional market demands, global economic conditions, and financial health of the petroleum sector also influence fiscal terms. It is commonly accepted that the level of government take is inversely proportional to the quality and availability of investment opportunities[9]. However, countries with harsh fiscal regimes or the greatest success probability provide no guarantees of the profitability of a project. Because the fiscal terms are only one of the elements that

[9] Page 2 – Omar, 1998

determine the profitability of a project, a "tough" contract may be highly profitable, while a very "favourable" contract may not be.

It is important to note that good fiscal design without complementary institutional structures may still not achieve the desired goals: design needs to be within the administrative and audit capacity of the relevant institutions. Therefore, a simpler system may be more viable than a theoretically ideal but complex to manage system. This is particularly important in countries that are new to the oil industry and/or have significant capacity constraints[10].

## 4. The National Development Plan and the petroleum industry.

South Africa has committed itself to a developmental state approach, which comes through strongly in the NGP[11] and the NDP[12]. The developmental state modelled on the East Asian experiences of high growth are defined by the clear vision of their economic goals, an ability to control the economy with economic instruments and prodding, a willingness to share risks, an excellent track record of institution building, and flexibility. The NGP states that:

> "There is growing consensus that creating decent work, reducing inequality and defeating poverty can only happen through a new growth path founded on a restructuring of the South African economy to improve its performance in terms of labour absorption as well as the composition and rate of growth. The Government is committed to forging such a consensus and leading the way by identifying areas where employment creation is possible on a large scale as a result of substantial changes in conditions in South Africa and globally."

The NDP commits government to the utilisation of gas as an alternative to coal, and recommends exploratory drilling for economically recoverable shale gas reserves, subject to the environmental implications. Increasing exploration to find domestic gas feedstock

[10] Page 23 – Tordo, 2007

[11] Patel, E. (2010). Framework for the Economic Growth Path. Cape Town: Parliament's economic development portfolio committee. 23 November 2010.

[12] Manuel, T. (2011).National Development Plan 2030: Our future- make it work, National Planning Commission, Pretoria, South Africa.

(including investigating shale and coal bed methane reserves) will diversify the energy mix and reduce carbon emissions[13].

The NDP states that:

"Substituting gas for coal will help cut South Africa's carbon intensity and greenhouse gas emissions. Possibilities include off-shore natural gas, coal-bed methane, shale gas resources in the Karoo basin, and imports of liquefied natural gas, which could be used for power production, gas-to liquid refineries and other industries.

New natural gas resources – enough to power at least a medium-sized power station – have been discovered off the West Coast. Further drilling may indicate that the resource is larger. The resource should be developed for power production in a phased way. Initial units will contribute to supply security, while encouraging further drilling and development.

Regionally available natural gas could either be piped to South Africa, for example from Namibia (recent finds in Mozambique are probably too far north to pipe economically), or it could be used in regional power plants with electricity transmission lines to South Africa.

Experiments are under way to assess the potential for mining coal-bed methane gas, although the overall potential of this resource for producing electricity in South Africa is probably less than previously thought. Underground coal gasification technology is also being developed.

According to the United States Energy Information Administration (US EIA), technically recoverable shale gas resources in South Africa form the fifth largest reserve globally. Confirmation of recoverable reserves is still necessary through further drilling of test wells. Even if economically recoverable resources are much lower than currently estimated, shale gas as a transitional fuel has the potential to contribute a very large proportion of South Africa's electricity needs. For example, exploitation of a 24-trillion-cubic-feet resource will power about 20 gigawatts (GW) of combined cyclegas turbines, generating about 130 000GW-hours (GWh) of electricity per year over a 20-year period

[13] On page 46 of the NDP prioritised infrastructure investment includes "Constructing infrastructure to import liquefied natural gas and increasing exploration to find domestic gas feedstock (including investigating shale and coal bed methane reserves) to diversify the energy mix and reduce carbon emissions."

This is more than half of current electricity production. South Africa should seek to develop these resources, provided the overall economic and environmental costs and benefits outweigh those associated with South Africa's dependence on coal, or with the alternative of nuclear power. The national value of this resource needs to be maximized.

A global market has developed for liquefied natural gas imports, the prices of which are increasingly delinked from oil prices. With South Africa needing to diversify its energy mix, liquefied natural gas imports and the associated infrastructure could provide economic and environmentally positive options for power production, gas-to-liquids production (at Mossgas) and other industrial energy uses.

Required infrastructure to re-gasify liquefied natural gas is becoming more affordable, with some ships incorporating these regasification capabilities onboard, combined with local submersible docking and pipeline facilities to deliver gas onshore. Investment should begin in liquefied natural gas infrastructure."

The NDP suggests the following steps to creating an oil and gas industry in South Africa, in the next five years (short-term):
South Africa needs to:

- "Do exploratory drilling for economically recoverable coal seam and shale gas reserves. Full investigations into whether the use of these resources is possible will continue, taking into account environmental implications.
- Develop West-Coast off-shore gas for power production by contracting private-sector service providers.
- Promote investment in liquefied natural gas landing infrastructure."

## 4.1 Energy security

The NDP commits government to exploring gas as a viable alternative to both coal and nuclear energy. It states that this shale gas "could make a significant contribution to South Africa's energy needs, whilst reducing greenhouse gas emissions and carbon intensity".[14]

The NDP estimates that between now and 2030, South Africa will need to meet an estimated 29,000 megawatts of new power demand whilst a further 10,900 MW of old power capacity will be retired – thus requiring about 40,000 MW of new power.[15] Eskom is currently building two more coal-fired power stations (namely Medupi and Kusile) of 4800MW each, leaving a clear gap between future needs and committed investments. The DOE's IRP, released in 2013, observes a downward revision in expected electricity use due to increased electricity prices, but projected declines are relative to a baseline only, and should not be interpreted as a fall in the absolute level of electricity demand relative to today's levels. With continued economic and population growth expected over time, baseline projections suggest that electricity consumption is still expected to increase substantially in absolute terms by 2030, provided that adequate electricity supply is available.[16]

The NDP 2030 vision is that South Africa will have an energy sector that promotes economic growth and development, and commits to investment in this sector so as to create new technologies and foster job creation.

It also commits to 95% of the population having access to electricity within 20 years. These are enormous challenges because this has to be achieved whilst keeping energy prices competitively low, to use as a strategic advantage. The current round of electricity price hikes to finance Eskom's infrastructure development illustrates the complexities as business and consumers have made submissions regarding the non-affordability of these price increases. There seem to be no alternatives to significant price increases in electricity under the current dispensation. The advantage of the shale gas is that it potentially allows South Africa to keep energy prices in check by providing local alternatives with an energy source with a price that is not as high as the price of oil. South Africa has a very energy intensive industrial sector and whilst it needs to examine new industrial models it has to accept that

[14] Page 143 – National Development Plan.

[15] Since the NDP was written the price of electricity has increased substantially, causing the pattern of electricity consumption to change, which may change these projections of demand.

[16] At page 7 - Bohlmann, J.A., Bohlmann, H.R. & Inglesi-Lotz, R. (2015*) An Economy-Wide Evaluation of New Power Generation in South Africa: The Case of Kusile and Medupi.* 9 June 2015. 2015-40. Department of Economics Working Paper Series. University of Pretoria

the existing industry needs to be supported and this requires stable energy sources at affordable prices. South Africa currently cannot guarantee either. South Africa recognises the need for major investments in new power capacity but does not have the financing model which keeps this affordable. Shale gas not only provides an indigenous energy source but also a potential fiscal windfall which allows us to finance the further development of this sector.

The development of the shale gas industry would have significant benefits. There are the direct impacts in terms of jobs and revenue. The procurement of goods and services can act as a multiplier for local economic development by contributing to employment, strengthening skills, and developing local suppliers and enterprises. The size of the economic multipliers in the oil and gas industry average 2.5[17] internationally, although some studies have found multipliers of greater than 5, and others less than 1. (A multiplier of 2.5 implies that every Rand spent by the industry will generate R2.50 in additional economic activity.) This sort of multiplier can have important spin-offs for economic development in the region. The two provinces which stand the most to gain directly are the Eastern and Western Cape which house most of the reserves. The Eastern Cape currently has the highest level of absolute poverty in the country, with 53.2% of the population living below the poverty line (compared to the national average of 42%), and amongst the highest levels of unemployment[18]. The government has already committed large sums of money to try and stimulate economic growth in the region, including the Coega project. But this has yet to result in significant returns and financial spin offs to investments in support industries – there is a need to generate sufficient economies of industrial scale to generate internal momentum. The shale gas industry, if properly organised, could provide such an impetus and further the developments of existing public infrastructure projects[19].

Development of all South Africa's offshore oil and gas fields (producing around 450 thousand barrels per day) would require direct employment of 20,500 skilled personnel and could support an oil service industry generating employment opportunities of around 33,000[20].

[17] Goloby, M. (2012). *The Oil and Gas Job Multiplier*. Pipeline and Gas Journal. June 2012 Vol. 239 No.6.
[18] Statistics South Africa (2014). *Poverty Trends in South Africa:* An examination of absolute poverty 2006 and 2011. Pretoria, South Africa.
[19] Page 144 - National Development Plan
[20] Ground, M., de Wet, W. & Leoka, T. (2013) Offshore Oil – the impact on South Africa's Economy. Commodities Special Report. Johannesburg: Standard Bank Research.

## 4.2 Economic growth

For over a century oil has been one of the biggest industrial sectors in the global economy. It is, in order of magnitude, larger than other commodity sectors. At an oil price of $64 per barrel global annual revenues are about $3.2 trillion. In contrast, at $ 1,145 per ounce for gold and $1,544 per tonne for copper, the world's annual gold and copper production are worth $108 billion and $180 billion, respectively. While the global oil industry is massively profitable, the majority of these profits accrue to governments through various forms of taxation[21] .

**Percentage Average Government take in oil and gas regions [22]**

| Country | Average Effective Tax Rate % |
|---|---|
| Poland | 28 |
| Ireland | 32 |
| Peru | 40 |
| South Africa* | 42,4 |
| Morocco | 43 |
| New Zealand | 45 |
| Papau New Guinea | 47 |
| Netherlands | 49 |
| US OCS Deepwater | 51 |
| United Kingdom | 51,5 |
| Argentina | 52 |
| Australia | 53 |
| Canada | 54 |
| Columbia | 55 |
| Philippines | 55 |
| India | 57 |
| US OCS Shelf | 57,5 |
| Mauritania | 58 |
| Thailand | 61 |
| Germany | 61 |
| Alaska (US) | 63 |
| Mozambique | 67,5 |
| Ecuador | 68 |
| Denmark | 69 |
| Angola | 69,5 |
| Indonesia | 71 |
| Malaysia | 71,5 |

[21] McGregor, S. (2014).Taxation of the South African Oil and Gas Industry, Draft Report to the Davis Tax Committee, Pretoria, South Africa.
[22] OECD (2013), OECD Economic Surveys: New Zealand 2013, Paris: OECD Publishing.

| Country | Average Effective Tax Rate % |
|---|---|
| Russia | 72 |
| Gabon | 72 |
| Brazil | 72 |
| Egypt | 73 |
| Norway | 75 |
| Bolivia | 77 |
| Kazakhstan | 78 |
| China | 80 |
| Trinidad & Tobago | 82 |
| Tunisia | 83 |
| Nigeria | 84,5 |
| Algeria | 85 |
| Oman | 88 |
| Yemen | 88 |
| Libya | 90 |
| Venezuela | 91,25 |
| Iran | 95 |

*** Average effective Tax Rate for South Africa inclusive of 20% state participation and Royalties (as determined by McGregor (2014))**

South Africa's economy grew at a subdued real rate of 1.5% in 2014, down from 2.2% in 2013, according to estimates of real GDP released by Stats SA. In terms of the new economic growth path South Africa's targeted growth is 7% GDP over 20 years[23] from 2010. Energy consumption is co-integrated with economic growth in South Africa[24]. This means that, in South Africa, increased energy consumption occurs with economic growth. If South Africa is to achieve its growth targets it will need increased access to energy resources. It is submitted that South Africa, however, needs to move away from the coal based economy.

In 2009 the US EIA quoted a volumetric range up to some 485 TCF as possible shale gas (unconventional resources) in place in South Africa. Shale gas development could be a 'game changer' for the South African economy. According to an Econometrix report[25], if just 10% of this unconventional resource is recoverable it would contribute toward annual employment that exceeds 700,000 jobs, annual value added in excess of R200 billion annually, and South African Government revenues estimated at R90 billion annually. The total value added by

[23] Patel, E. (2010). Framework for the Economic Growth Path. Cape Town: Parliament's economic development portfolio committee. 23 November 2010.
[24] At page 6 - Esso, J.L. (2010). The Energy Consumption-Growth Nexus in Seven Sub-Saharan African Countries, Economics Bulletin, 30(2):1191-1192.
[25] At page 97 - Econometrix, 2012. Karoo shale gas report: special considerations surrounding potential shale gas resources in the southern Karoo of South Africa. Available at: http://www-static.shell.com/static/zaf/downloads/aboutshell/econometrix/econometrix_report.pdf

shale gas could be between 3.3% and 9.6% of South Africa's GDP at 2010 levels, or between 1.1% and 2.8% of projected 2035 GDP levels. In terms of employment, the modelled values represent between 2.7% and 6.5% of 2010's measured employment level, or between 0.98% and 2.4% of the projected level of employment, given sustained 4.5% pa growth in GDP to 2035. Average Government revenue equates to between 4.6% and 11.8% of 2010's level, or between 1.5% and 3.9% of projected 2035 Government revenue levels[26].

## 4.3 Jobs and employment

Whilst South Africa's oil and gas industry is still nascent, it is difficult to predict what the impact of a significant discovery might imply to the creation of jobs and employment. At best, an estimate may be based on the impact of the oil and gas sector in other countries.

In the United Kingdom, the multipliers in the oil and gas sector illustrate a 3 x multiplier of indirect jobs and a 6 x multiplier of induced employment for every direct job created. Mozambique oil and gas activities, as conducted by Anadarko, have seen similar multiplier effects. In the Palma district an average of 1,300 FTE jobs per month were created in 2013. Moreover, it is forecast that 114,800 new jobs will be created from 2018 to 2039, annually, in Mozambique, with respect to its LNG project[27].

Standard Bank [28] reports that if all the offshore fields in South Africa were to be developed, producing around 450kbd (thousand barrels per day) at an oil price of $110/bbl, in terms of job creation this would require around 20,500 skilled personnel. Such an exploitation of South Africa's offshore resources would necessitate a significant expansion of the country's oilfield services industry. Utilising overseas oilfield service industries as a benchmark, Standard Bank calculates that a 450kbd production could support an oilfield service industry generating employment opportunities of around 33,000 predominately unskilled jobs.

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[26] Econometrix Report 2012

[27] Ranosek, M. (2014). Presentation to Davis Tax Committee: Offshore Oil and Gas Industry of South Africa, Pretoria, South Africa.

[28] At page 1 - Ground, M., de Wet, W. & Leoka,T. (2013) Offshore Oil – the Impact on South Africa's economy. Commodities Special Report. Johannesburg: Standard Bank Research.

According to the Wait Study[29], fiscal systems that promote GDP growth are less attractive in terms of investment promotion. Countries still in the exploration phase should opt for fiscal systems that promote investment, and shift their focus to GDP growth once the industry has had sufficient time to develop. Even if attracting investment in the oil and gas sector does not yield significant tax revenue for the fiscus (and contribute substantially toward GDP as a percentage), the multiplier effect of such an investment provides the platform for job creation.

## 4.4 Balance of payments

Standard Bank[30], furthermore, reports that if South Africa were to produce 450kbd domestically, it could wipe out roughly ZAR169bn worth of merchandise imports (specifically crude oil and refined products), which means that the current account deficit, as a percentage of GDP, could be reduced to -0.9%.

In addition, a more balanced current account due to reduced reliance on oil imports could see greater stability in current account balances, as imports will be less subject to the volatility of global oil prices and currency movements.

The main advantage of a smaller and possibly more stable current account is a potentially more stable currency.

## 4.5 Environment issues

Under the Constitution, everyone has the right to have the environment protected for the benefit of present and future generations. 'Sustainable development' is the term used for the integration of social, economic and environmental factors into planning, implementation and decision making processes for the benefit of present and future generations.

[29] At page 14 - Wait, R. , Rossouw, R., Loots, E. and Bezuidenhout, H. (2015) The effects of licensing and tax policy on the development of the upstream oil and gas sector: the case of South Africa. Potchefstroom, School of Economics, North-West University.
[30] At page 3 – Standard Bank Research (2013)

In 2012, a Working Group of the Task Team on Shale Gas and Hydraulic Fracturing (the Working Group) was chaired by the CEO of Petroleum Agency SA and comprised representatives from the following departments and institutions: Departments of Environmental Affairs, Science and Technology, Energy, Mineral Resources, Water Affairs, the Petroleum Agency, Council for Geoscience, SKA South Africa, Water Research Commission, and ESKOM.

The terms of reference of the Working Group study are derived from the terms of reference of the Task Team, and focussed on evaluating both the positive and negative aspects of shale gas exploitation. The study aimed to evaluate the potential environmental risks posed by the process of hydraulic fracturing ("Fracking") as well as the negative and positive social and economic impacts of shale gas exploitation.

The use of large volumes of water together with chemical additives makes it essential that the environmental and social implications of the Fracking process are considered. The Task Team study considered the impact of shale gas exploitation on land use, water use and air pollution. Whereas existing environmental regulations were considered to adequately cover most of these factors, a concern that was highlighted by the Task Team which required additional attention, is water usage and disposal: in particular, the volume and transportation of the water, the potential contamination of water resources and the disposal of 'used' fracturing fluid. The use and disposal of water in such large amounts is expected to require a water use licence under the National Water Act.

Further research is required to investigate all potential sources of input water, as well Investigation of Hydraulic Fracturing: Report of the Working Group as means of water disposal. Extensive hydrological and geo-hydrological studies, before exploration and production drilling, will be required in order to minimise or eliminate potential impacts on other users. Because of the uncertainty regarding the extent, or even existence, of economically producible reserves, any assessment of the potential economic impact is subject to enormous uncertainty[31].

[31] Working Group of the Task Team on Shale Gas and Hydraulic Fracturing, 2012. Available at: http://www.dmr.gov.za/publications/summary/182-report-on-hydraulic-fracturing/853-full-report-on-investigation-of-hydraulic-fracturing-in-the-karoo-basin-of-south-africa-.html

## 5. History of oil and gas exploration and production

Although local exploration for crude oil started as early as 1888 in the Boshof and Potchefstroom districts, the first organised search for hydrocarbons in South Africa was undertaken by the Geological Survey of South Africa in the 1940's[32]. In the 1960s and 1970s initial petroleum exploration took place in the Karoo Basin. The interest was therefore initially only centred onshore. Although several natural gas finds were made onshore, such as the Evander find, no substantial commercial discovery of oil or gas was made at that stage. As a result, the focus of exploration activities shifted offshore, to the continental shelf, due to the perceived low potential for large conventional oil onshore[33].

In 1965 Soekor (Pty) Ltd was formed by the government in order to explore and exploit natural gas for itself, on behalf of the state, or on behalf of any other person. A Prospecting Lease (No. OP26) was granted to Soekor whereby the government, through Soekor, undertook to prospect for oil and gas, which resulted in the discovery of the F-A/EM gas fields from which PetroSA still produce gas today[34].

In 1967 a new Mining Rights Act was passed and offshore concessions were granted to a number of international companies including Total, Gulf Oil, Esso, Shell, Atlantic Richfield Company , Compagnie Française des Pétroles and Superior. This led to the first offshore well being drilled in 1969 and the discovery, by Superior, of gas and condensate in the Ga-A1 well situated in the Pletmos Basin.

In 1970, Soekor (together with Rand Mines) extended its efforts offshore but, despite further encouraging discoveries, international companies gradually withdrew. This was largely as a result of political sanctions against South Africa. Thus, from the mid 1970's to the late 1980's Soekor, the State owned oil and gas exploration company, was the sole explorer operating the entire offshore area of South Africa. The offshore areas were, again, opened to international investors via a Licensing Round held in 1994.

[32] Page 48 – Maas,1990
[33] At page 15 - Department of Mineral Resources' Report on Investigation of Hydraulic Fracturing in the Karoo Basin of South Africa, 2012
[34] At page 69 – Maas,1990

In 1999 Petroleum Agency SA was established, and in 2001 a new State oil company, PetroSA, was formed by the merger of Soekor and Mossgas. The MPRDA was passed in 2002, and became operational on 1 May 2004.

In the entire offshore area there are now over 300 exploration wells, including appraisal and production wells. In addition, 233 000 km of 2D seismic data and 10 200 km2 of 3D seismic data have been acquired since exploration began offshore in 1967[35].

Exploration drilling was most active from 1981 to 1991, during which period some 181 exploration wells were drilled. The Bredasdorp Basin has been the focus of most seismic and drilling activity since 1980.

The results of this exploration are the discovery of several small oil and gas fields, and the commercial production of oil and gas from the Bredasdorp Basin. In the Pletmos Basin there are two undeveloped gas fields and a further six gas discoveries. One oil and several gas discoveries have been made in the South African part of the Orange Basin [36].

Over the past five years there have been two developments which have created renewed interest in South Africa as a potential oil and gas producer. The first of these game changing events has been the discovery of massive natural gas fields off the coast of northern Mozambique. This has renewed interest among major oil companies in exploring South Africa's offshore continental shelf. The fact that gas has been discovered in Namibian waters, at the mouth of the Orange River, off Mossel Bay, and off northern Mozambique suggests that there may be other viable gas deposits in South African waters.

The second, and possibly the more important, development is the fracking revolution in the United States. Until recently, almost all oil and gas production came from reservoirs in porous rocks. The technical revolution known as 'fracking' has made it possible to economically extract oil and natural gas from non-porous shale. The rapid roll out of fracking in the United States has transformed the global oil and gas industry. Despite high prices, production from conventional oil reservoirs has been almost static for the past five years. The surge in US output has met the oil requirements of rapidly growing emerging markets and more recently flooded the market, causing a dramatic collapse in prices. Earlier

[35] VanderSpuye, D (2011) – Oil and Gas Exploration and Production in South Africa: The Players. Petroleum Agency of South Africa.
[36] At page 11 – Ranosek, 2014

exploration suggests that the Karoo shale may prove suitable for fracking, raising the possibility that South Africa could, at last, become a significant producer of natural gas[37].

## 6. Who are the major role players or stakeholders in South Africa?

### 6.1 Department of Mineral Resources

DMR regulates the minerals and mining industry in terms of the prescripts of the MPRDA. DMR promotes the minerals and mining sector of South Africa. DMR safeguards the health and safety of mine employees and people affected by mining activities by monitoring and enforcing compliance with relevant laws.

### 6.2 Department of Energy and National Energy Regulator of South Africa

The DOE oversees the development of energy policy and implementation thereof. The department's website describes its function as ensuring exploration, development, processing, utilisation and management of South Africa's mineral and energy resources. Energy policy and its subsequent legislative and regulatory frameworks are the foundation upon which the regulator and investors make decisions and consumers make choices about which energy solution to use. [38]

The 1998 national White Paper on Energy Policy is the most comprehensive energy policy document to date, and is the primary reference for all subsequent legislation. One of the medium term policy priorities, identified for the energy sector, is to stimulate economic growth.

National policies that are relevant to the fuel and related industries include the NDP and the IPAP. The NDP directly addresses fuel and gas, emphasising the need for adequate supply security of energy such that economic activity, transport, and welfare are not disrupted. With regards to liquid fuels the NDP identifies declining gas stocks for the gas to liquids

[37] At page 1 – Mc Gregor, 2014
[38] Beare, M. (2013) 'Is the Coega (Mthombo) oil refinery in South Africa viable?', Masters thesis. Stellenbosch: Department of Economics, Stellenbosch University.

production at PetroSA and increasing dependence on imported product, due to insufficient domestic production capacity, as the main challenges. It calls for the upgrading of fuel refineries to ensure compliance with new fuel quality standards (clean fuels 2) and closer management of strategic fuel stocks to ensure security of supply. Regarding gas, it calls for a conducive environment to exploratory drilling, and fast tracking of development of resources in the event of success. There is also an emphasis on the incorporation of a greater share of gas in the energy mix, both through importing liquefied natural gas and, if reserves prove commercial, using shale gas.

IPAP notes a concern regarding mineral feedstocks supplied into the South African economy at monopoly prices and subsequently severely curtailing downstream job creation. Polymers is one such example. In recognition of the limitations of competition policy in addressing such issues, IPAP 5 further calls for the identification of concrete complementary measures to competition enforcement, as part of a broader policy toolkit that could be deployed to address anti-competitive behaviour. The 2014 version, IPAP 6, proposes the regulation of polymer chemicals as an alternative solution to the anti-competitive concerns.

Aspects of the South African petroleum value chain are regulated largely under the mandate of the DOE and administered either directly or by NERSA. The DOE is responsible for the setting of various price levels for petroleum products, and licensing activities throughout the downstream liquid fuels value chain in terms of the Petroleum Products Act, No 120 of 1977, as amended. NERSA sets tariffs for the infrastructure linked to the value chain e.g. petroleum pipelines and storage facilities.

## 6.3 Petroleum Agency of South Africa

PASA promotes exploration for onshore and offshore oil and gas resources and their optimal development on behalf of government. The Agency regulates exploration and production activities, and acts as the custodian of the national petroleum exploration and production database, and is the repository of important public managed geological data.

PASA provides valuable services to both government and industry in that it:

- ensures consistency between approaches of various petroleum companies;
- ensures consistency of processes and procedures;

- establishes one port of call for all relevant upstream petroleum information;
- provides quality assurance of data obtained during drilling;
- ensures that well tests are completed when necessary;
- ensures that petroleum companies comply with their work programme commitments;
- holds copies of all acquired data on behalf of the government;
- maintains the national database of all petroleum activity data;
- verifies and approves discovered and potential reserves / resources in the country (which is essential for governmental long term energy planning); and
- ensures that the correct royalties and other taxes are paid on the stated reserves and production by petroleum companies.

International experience suggests that it is best to have a dedicated oil and gas regulatory authority – certainly the majority of the successful developing oil and gas jurisdictions in Africa (and around the world) have a dedicated oil and gas regulatory body. For example, Mozambique, Mali and Algeria (which have all adopted models similar to PASA) and the world class, dedicated, agencies in Brazil and Columbia.

## 6.4 National Oil Company

PetroSA is South Africa's National Oil Company (NOC) and has a mandate to represent the State's interest in the oil and gas sector in South Africa, to ensure security of oil and gas supply and to be a catalyst for transformation. In doing this it reports to the Department of Energy.

While PetroSA was formed, in January 2002, through the merger of three previous entities: Mossgas (Pty) Limited, Soekor (Pty) Limited, and parts of the Strategic Fuel Fund Association, it has retained the petroleum exploration and production knowledge base and experience gained since 1965. PetroSA holds commercial interests in 7 oil and gas blocks offshore of South Africa. These are Block 9 and 11a, Block 1, Block 2A, Block 2C, Block3A/4A and Block 5/6.

The MPRDA Amendment Bill proposes State Participation to be held by a designated State owned entity. It is anticipated that in relation to Petroleum Resources, PetroSA will be gazetted as the State owned entity to house the State Participation.

## 6.5 Oil and gas rights holders

The Oil and gas rights holders are represented by the OPASA and the ONPASA. These associations represent the collective interests of major IOCs and smaller independents.
OPASA was officially launched in May 1999. The DME, and others interested in the upstream industry of South Africa, joined with companies involved in the offshore exploration and production of hydrocarbons to announce this organisation.

OPASA provides a forum for formal and informal discussion and information exchange, practical co-operation, and joint liaison with the State on specific issues. A prime objective is to co-operate with the State and all stakeholders in promoting health, safety, and sound environmental practices.

Activities in which OPASA is involved in include: general public awareness of the offshore petroleum industry, promoting compliance with good oilfield practices, promoting care of the environment, liaison with interested and affected parties, pooling of resources for emergency response, industry dialogue with the State and co-operation on operational matters.

The OPASA members, which currently hold oil and gas rights, are comprised of:

- Impact Oil & Gas
- ExxonMobil Exploration and Production South Africa Ltd
- Cairn South Africa (Pty) Ltd
- The Petroleum Oil and Gas Corporation of SA SOC Ltd
- Thombo Petroleum Limited
- BHP Billiton Petroleum Limited
- Sasol Petroleum International (Pty) Ltd
- Global Offshore Oil Exploration (SA) (Pty) Ltd
- CNR International (South Africa ) Limited
- New Age (African Global Energy) South Africa Ltd

- Silverwave Energy PTE Ltd
- Shell South Africa Upstream BV
- Sungu Sungu Petroleum
- Anadarko South Africa (Pty) Ltd
- Total E&P South Africa (Pty) Ltd
- Sunbird Energy (Ibhubesi) (Pty) Ltd
- Statoil ASA
- ENI South Africa BV

### 6.6 Service providers to oil and gas rights holders

The SAOGA is an outgrowth of a provincial government sector development programme around the oil and gas industry in the Western Cape Province of South Africa (a region that includes Cape Town, Mossel Bay and Saldanha Bay). This programme was focused on a significant cluster of upstream supplier companies that developed in the province in response to upstream growth in West Africa and the establishment of domestic production in Mossel Bay in the late 1980s.

An independent non-profit entity known as the Cape Oil and Gas Supply Initiative (COGSI) was established in 2003 to become the main vehicle for promoting and developing the sector. The Board was subsequently renamed COGSI the South African Oil and Gas Alliance to reflect the growing involvement of upstream suppliers from other regions and the fact that no other South African organisation focuses on the upstream supplier base.

Today SAOGA has a national footprint and focus although the Western Cape remains the *de facto* centre of upstream supplier activity in South Africa.

## 7. The offshore oil and gas sector value chain

The life stages of an oil and gas field can be described as follows:

1. *Licensing:* In most cases the host government grants a licence (lease, or block area) or enters into a contractual arrangement, with the oil and gas company, to explore for and develop a field, without transferring the ownership of the mineral resources. The licensing stage commences in South Africa with the issuance of an exclusive TCP

for a period of 12months. Typically, during this period, the oil and gas right holder will acquire historical seismic data for the block from PASA and assess such seismic data, to decide whether or not to proceed to the exploration stage.

2. *Exploration:* After acquiring the rights, the oil and gas company carries out geological and geophysical surveys, such as seismic surveys and core borings. The data so acquired is processed and interpreted and, if it appears promising, exploratory drilling is carried out. Depending on the location of the well a drilling rig, drill ship, semi-submersible, jack-up, or floating vessel will be used. The exploration stage commences in South Africa with the issuance of an exploration right for 3 years. The costs incurred on a deep-water oil and gas block in the exploration stage are estimated at $280mil.
3. *Appraisal:* If hydrocarbons are discovered, further delineation wells are drilled to establish the amount of recoverable oil, production mechanism, and structure type. Development planning and feasibility studies are performed, and the preliminary development plan is used to estimate the development costs. Approximately 1 in 16 appraisal wells drilled internationally are recognised as commercial discoveries. The appraisal stage, in South Africa, is marked by the renewal of the exploration right for a further 2 years (with the option to renew a further 2 times). The costs incurred on a deep-water oil and gas block in the appraisal stage are estimated at $1billion to $2billion
4. *Development:* If the appraisal wells are favourable and the decision is made to proceed, then the next stage of development planning commences using site-specific geotechnical and environmental data. Once the design plan has been selected and approved, contractors are invited to bid for tender. Normally, after approval of the environmental incompact assessment, by the relevant government entity, development drilling is carried out and the necessary production and transportation facilities are built. The development stage in South Africa commences with the issuance of the production right. The production right is issued for a period of 30 years. The costs incurred on a deep-water oil and gas block in the development stage will vary in accordance with the number of development wells drilled. The costs incurred on a deep-water oil and gas block, in the development stage, are estimated at $2billion to $4,5billion.
5. *Production*: Once the wells are completed and the facilities are commissioned, production starts. Work-overs must be carried out periodically to ensure the

continued productivity of the wells, and secondary and/or tertiary recovery may be used to enhance productivity at a later time. The timeframe to entering the production stage in an oil and gas field is long, with production start-up typically 7-10 years from commencement of the exploration stage.

6. *Abandonment:* At the end of the useful life of the field, which for most structures occurs when the production cost of the facility is equal to the production revenue (the so-called "economic limit"), a decision is made to abandon. For a successful removal, oil and gas companies generally begin planning one or two years prior to the planned date of decommissioning (or earlier depending on the complexity of the operation).

# 8. Current non-tax legislative and policy regime

## 8.1 MPRDA

The MPRDA makes provision for equitable access to, and sustainable development of, South Africa's mineral and petroleum resources. The objects of the MPRDA (section 2) are:

a) Recognise the internationally accepted right of the State to exercise sovereignty over all the mineral and petroleum resources within the Republic;
b) Give effect to the principle of the State's custodianship of the nation's mineral and petroleum resources;
c) Promote equitable access to the nation's mineral and petroleum resources to all the people of South Africa;
d) Substantially and meaningfully expand opportunities for historically disadvantaged persons, including women, to enter the mineral and petroleum industries and to benefit from the exploitation of the nation's mineral and petroleum resources;
e) Promote economic growth and mineral and petroleum resources development in the Republic;
f) Promote employment and advance the social and economic welfare of all South Africans;
g) Provide for security of tenure in respect of prospecting, exploration, mining and production operations;
h) Give effect to section 24 of the Constitution by ensuring that the nation's mineral and petroleum resources are developed in an orderly and ecologically

sustainable manner while promoting justifiable social and economic development; and

i) Ensure that the holders of mining and production rights contribute towards the socio-economic development of the areas in which they are operating.

## 8.2 Licensing regime: Technical Cooperation Protocols, Exploration and Production Rights

There are two permits and two rights that may be issued or granted with respect to oil and gas exploration and production in South Africa. These are:

1. *Reconnaissance Permit*

   This permit allows a company to undertake a reconnaissance survey, for example, a speculative seismic or geochemistry survey. The permit is valid for 12 months, is not exclusive and is neither transferable nor renewable.

2. *Technical Cooperation Permit*

   This permit allows for the exclusive desk-top study of an area, utilising existing data. The permit is valid for 12 months and is neither transferable nor renewable. The permit holder has an exclusive right to apply for an Exploration Right.

3. *Exploration Right*

   This is an exclusive right to explore for petroleum and includes the right to produce (for testing). The right is transferable and contains a "use it or lose it" clause. The initial period is 3 years, followed by three renewal periods of 2 years each i.e. the right may run for a total of 9 years.

4. *Production Right*

   This is an exclusive right to produce petroleum. The right is transferable and may last for up to 30 years. It can be renewed for a further term.

The time periods allocated for exploration and exploitation of oil and gas resources compare favourably to other countries:

**Exploration and Exploitation periods**[39]

[39] Barrows, G.H. (1993). Worldwide Concession Contracts and Petroleum Legislation. Pennwell Books, Oklahoma.

| | Exploration | Exploitation |
|---|---|---|
| Algeria | 3yrs+ 2yrs +2yrs | 32 years |
| Benin | 3yrs + 3yrs + 3yrs | 25yrs + 10yrs |
| Chad | 5yrs + 3yrs | 25yrs + 10yrs |
| Columbia | 6yrs + 2yrs | 24yrs + 10yrs |
| Ecuador | 4yrs + 2yrs | 35 yrs |
| Mauritania | 10yrs | 25-30yrs |
| South Africa* | 3yrs + 2 yrs + 2 yrs +2 yrs | 30yrs |

## 8.3 Conversion of old order rights to new order rights

Immediately prior to May 1, 2004, the principal legislation governing mineral rights in South Africa was the Minerals Act, which came into effect in 1991. The MPRDA that came into effect on May 1 2004 replaced the Minerals Act. The MPRDA contains certain transitional measures with regard to mineral rights, prospecting permits, and mining authorizations (old order rights) obtained prior to May 1 2004.

Old order rights held under the previous dispensation were required to be converted to (new order) rights recognized under the MPRDA. In accordance with the transitional arrangements of the MPRDA all applications for prospecting permits, mining authorizations, consent to prospect or mine, and all environmental management programs made under the Minerals Act but not finalized or approved before May 1 2004 (the date on which the MPRDA took effect), were treated as having been made under the MPRDA.

## 8.4 Proposed MPRDA amendments: policy uncertainty and current status of exploration

State participation was not legislated in the MPRDA, 2002. Reference to State participation was founded in the Mining Charter and, in practice, was contained in the template of MPRDA production rights. In the template of the MPRDA production rights it was indicated that the State participation was to be 10 per cent. The IMF's simulation results show that in the scenario of 10% State participation and 10% BEE[40], the South African Average Effective Tax Rate (AETR) is 47.7%,

The 2014 Amendment Bill for the MPRDA introduced the possibility of a 'free carried interest' of 20 percent in petroleum ventures, with the option of additional paid equity interests. The State's fee carry is an important consideration for international investors. This, together with the allocation to HDSA, at 10%, could influence marginal decisions on whether or not to invest[41]. The IMF's simulation results demonstrate an increase in the South African AETR to 58.9%, in the scenario of 20% State participation and 10% BEE[42].

The concept of State participation is not new in the context of mining for petroleum resources. It is the premise of the production sharing contracts/agreements, but is also seen in concession right regimes in conjunction with separate tax legislation.

It is understood that the State participation, as formulated in the MPRDA amendment, is a non-fiscal intervention, by DMR, in search of Government 'control' of petroleum resources or technology and skills development benefits. Nonetheless, together State participation and South Africa's fiscal terms form the holistic 'government take' against which an upstream petroleum company will make a decision to invest in South Africa, and engage in the exploration and production of gas and oil:

$$\text{Government take} = \frac{\text{(1- IOC after tax cashflow)}}{\text{Gross Rev – opex- capex}} \times 100 = \%$$

[40] Page 12 – South Africa Current Regime Simulation Results, IMF 2016

[41] Page 25 – Mining Report. (2015). BBBEE in the mining industry is regulated by the amended broad-based socio-economic empowerment charter for the South African mining and minerals industry (the Mining Charter), promulgated in 2010 in terms of the MPRDA. The charter imposes various targets, including, amongst other ones, required percentage levels for procurement of goods and services through BEE entities and levels of ownership necessary to achieve BEE status (currently set at 26% by 2014). Highly topical at the moment is the issue of whether a company which has achieved empowerment status continues to be empowered if a BEE person disposes of its BEE shareholding to a non-BEE person, i.e. whether the "the once empowered always empowered principle" applies. In this regard government is seeking a declaratory court order on the issue: see: http://www.bdlive.co.za/opinion/columnists/2015/04/09/sticky-issue-of-ownership-at-heart-of-empowerment; last accessed 9 April 2015 [Ed. also Money Web discussion approx. 18th June 2015]. The 10% applied for oil and gas is in accordance with the Liquid Fuels Charter.

[42] Page 12 – Scenario 2 Simulation Results, IMF 2016

The below table reflects the calculated effective tax rate at various levels of free carried interest (without taking the BEE shareholding into account):

| Free Carried Interest % | Effective Tax Rate % |
|---|---|
| **0** | **28.0** |
| **10** | **35.2** |
| **20** | **42.4** |
| **30** | **49.6** |
| **40** | **56.8** |
| **50** | **64.0** |

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The concept of mandatory indigenous participation such a HDSA or BBBEE is also not a concept unique to South Africa. Mandatory indigenous participation at ownership level is found in Nigeria, prescriptions with regard to the number of local employees to the appointment of one foreign person are found in Equatorial Guinea, Mozambique and Egypt, and prescriptions with regard to use of local suppliers when procuring services and goods are imposed in Nigeria and Ghana as conditions for the issuance of import permits for capital items duty free.

## 8.5 State Intervention in the Mining Sector (SIMS) report and the proposed windfall tax

The SIMS[44] report calls for a fair share of resource rents for the State.[45] It is thought that, in this context, the SIMS report is seeking the imposition of a windfall tax in the context of high commodity prices. The SIMS report does not propose how a fair share amount should be determined. Here, Government has to strike a careful balance to ensure that the tax imposed does not transgress tax neutrality (and discourage investment by over-reaching) but at the same time enables Government to collect adequate resource rents.

The past ten years have been characterized by extreme volatility in oil and gas prices. As crude oil prices soared toward $147 per barrel in July 2008, so did political pressure to increase “government take.” Host governments around the globe entered a race to capture

[43] Page 7 – Mc Gregor, 2014. Modelling results are reflective of State Participation only and do not include allocation to BEE.
[44] ANC Policy Document (March 2012.) ”Maximizing the Developmental Impact of the People’s Mineral Assets: INTERVENTION IN THE MINERALS SECTOR (SIMS)”- ANC Policy Discussion Document.
[45] Page 36 - SIMS

the perceived windfall. The investment climate became volatile, owing to repeated government action to adjust government take. Regulatory and contractual frameworks became just as volatile as the commodity prices. A wave of increased taxation, contract renegotiation, and nationalizations spread around the globe. The resulting fiscal systems and contractual arrangements focused primarily on capitalizing on the high oil price, often failing to provide contingencies in the event of a downward spiral.

The precipitous drop in oil prices from $147 per barrel to below $40 per barrel within a four month period, in 2008, was accompanied by another shift in regulation of upstream fiscal systems, albeit at a significantly lower pace and intensity. Several governments were forced to backtrack and either partially or totally reverse course. Other governments that did not engage in this "race to the top" seized the opportunity to attract investment in the midst of a global economic crisis.

In this "race to the top" or "race to the bottom," depending on the perspective, governments share the same goal: developing the resource for the benefit of their citizens. Although the goal may be the same, the approaches and policies vary considerably. A nation's energy policy is shaped by its economic development needs, relative geological prospectivity or resource size, dependence on hydrocarbon revenues, protection of the environment, and other factors. Government actions are a reflection of the way governments balance these policy objectives. The success or failure in this race is measured not by what position a given nation takes in a ranking of government take or other indexes, but rather by whether the nation has reached its policy objectives[46].

In this regard, South Africa's National Treasury makes the following point in support of the need to design taxes soberly without undue regard to short term economic cycles[47]:

> "A general trend seems to have emerged that is fundamentally driven by periods of ups and downs in commodity prices. When commodity prices are on the increase (e.g. during the 1970s price shocks and 2002-2008 commodity boom), nationalisation and/or capturing higher rents tend to list high on governments'

[46] Agalliu, I. (2011) Comparative assessment of the Federal Oil and Gas Fiscal System. Massachusetts, United States: IHS CERA

[47] Page 9 - National Treasury ( March 2013)." Mining taxation – the South African context: Economic Tax Analysis"

agendas, while a decrease in prices (experienced during 1980s and 1990s) has led to calls for privatisation and restricting government's role to one of regulation and investment promotion. Other influential factors include changes in ideology linked to changes in governments and the re-negotiation of charters / commitments where perhaps previous agreements were concluded during less favourable periods. This entrenches the concept that a country should design its mineral fiscal regime very carefully to avoid changes based on commodity booms and busts or the ideology of the day. The ideal should be a stable regime that factors all elements in i.e. commodity prices, profitability and risks".

The volatility of commodity pricing has recently seen the cumulative oil price decline between June 2014 and January 2015 from a four year average of $105bbl to just $42bbl. The price of oil, at 5 July 2016, was $47,96bbl and it is forecast to remain in a range below $65bbl to 2017. This decline is the third largest of the past 30 years (when oil began trading in futures exchanges) and was driven by a "perfect storm" of conditions all external to the South African oil and gas industry, that exerted strong downward pressure on prices[48]. Given the current decline in commodity prices and the rand exchange rate, the Sovereign Wealth Fund, as proposed in the SIMS report to house windfall taxes, appears to have lost its allure, with Economic Development Minister, Ebrahim Patel, indicating that plans for such a fund are being indefinitely[49] postponed. Furthermore, the Mining Report does not support the enactment of a dedicated windfall tax[50].

## 8.6 Resource rent tax

Over the last few years, there have been various calls to change or introduce new tax instruments to the mining tax system, such as windfall taxes, resource rent taxes, surcharges based on cash flows and separate flat royalty charges. The IMF[51] recommends a RRT as a reform option in highly profitable circumstances.

[48] Baffes, J. ,Ayhan Kose, M.,Ohnorge, F. & Stocker, M. (2015) *The great plunge in oil prices: Causes, Consequences and Policy Responses.* Policy Research Note. World Bank Group. March 2015

[49] See http://www.moneyweb.co.za/moneyweb-economic-trends/sas-sovereign-wealth-fund-off-the-table

[50] Page 83 – Mining Report.

[51] Page 36- - Daniel, P., Grote, M., Harris, P. & Shah, A. (2015). Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges. Report prepared for Davis Tax Committee. Pretoria: International Monetary Fund.

An RRT seeks to tax surplus profits at a relatively high rate so that government can enjoy a greater take in such surplus. Surplus profits are seen as being profits in excess of that amount which covers an investor's risk and required return on investment. Proponents of RRT's justify the tax particularly in relation to minerals on account of the latter being owned by the State. While the RRT has much theoretical appeal, it has not been a significant revenue raiser in practice[52]. There may be many reasons for this. It could reflect the difficulty of designing the tax, particularly the choice of the discount (or hurdle) rate and tax rate. If the hurdle rate is set too high, chances are that the RRT will never apply; if it is set too low, the tax may become a major deterrent to investment. If either the hurdle rate of return is too low or the tax rate too high, the RRT will also increase the incentives for oil companies to engage in tax avoidance which, in countries with a weak tax administration, may be very difficult to detect and control.

The Davis Tax Committee Mining Report takes the view that new tax instruments are not necessary, particularly since the Royalty formula (see 9.3 below) accommodates both up and down cycles in the profitability of the minerals industry, in determination of the rate of royalty. Furthermore, the calculation of the Royalty is fairly straightforward and much simpler to administer and comply with than a RRT (that requires defining and calculating an appropriate tax base and a 'normal rate of return'). When comparing South Africa's Royalty regime with a RRT in this sense, the latter is more difficult to administer – both in terms of defining the tax base and calculating the rent[53].

The IMF re-positioned the context for the application of a RRT in the presentation of its oil and gas findings, held on 8 March 2016, and the Additional Analysis performed for the Davis Tax Committee (provided in June 2016), to state that the IMF is not advocating a RRT, but rather a cash flow surcharge as an additional rent tax mechanism that allows the State to receive a portion of the resource rents as they arise[54].

[52] Sunley, E.,Baunsgaard, T. and Simard, D. (2002). Revenue from the Oil and Gas Sector: Issues and Country Experience. Background paper prepared for the IMF conference on fiscal policy formulation and implementation in oil producing countries, June 5-6, 2002.
[53] Page 16, National Treasury ( March 2013)." Mining taxation – the South African context: Economic Tax Analysis".
[54] Page 3, Summary of issues – State Participation/Cash Flow Surcharge, IMF 2016

# 9 Current tax regime and its performance

As discussed earlier, in section 3 above, the hydrocarbon minerals industry (such as oil, gas and coal) has a number of special features which make it quite distinct from most other industries and other forms of economic activity. These differences relate to: size of investment, timescale, and the non-renewable nature of hydrocarbon mineral resources.

Because of the distinctive features of the hydrocarbon mineral extraction industry there's a tendency amongst governments to subject it to a specific tax policy. Correspondingly, the taxation of revenues from crude oil and natural gas reserves in South Africa has been subject to tax rules (Tenth Schedule to the Income Tax Act) that are significantly different from those applicable to other operations (including other resource operations such as mining).

Clegg & Steenkamp[55] indicate that the reason for the special treatment of oil and gas exploration and production (in this instance, in South Africa) is rather obvious. First of all, the discovery and production of oil and gas within a specific country's territory is usually of great strategic significance, since it may lead to the generation of substantial foreign revenue for the country, and may also decrease the dependency of a country on external sources to satisfy its energy needs. Since the exploration for oil and gas is an extremely costly, and a medium-to-long term exercise, governments have identified the need to make it attractive for local and global companies to invest in oil and gas exploration and production in their countries.

The most popular method to do this has consistently been to reward such companies with a beneficial tax regime. Countries with less favourable geological conditions normally offer better fiscal terms, while those perceived to have more potential offer tougher terms. Investment in hydrocarbon exploration will only occur if a combination of the fiscal terms, geological reality and the oil (or gas or mineral) price make it worthwhile to invest[56].

It is an unfair statement to label South Africa as a country with poor geological prospectivity for oil and gas reserves. In the entire offshore area there are now over 300 exploration wells including appraisal and production wells. However, an examination of offshore exploration

[55] Page 1 - Clegg, D. & Steenkamp, L. (2007) Oil and gas exploration and production in South Africa – A new tax regime. Cape Town: Ernst & Young.
[56] Page 2 - Omar, Anwar. (1998). The Historical Development of Income Tax on South African Hydrocarbon Production: 2. Oxford Project Report. The College of Petroleum and Energy Studies.

activity and discoveries in South Africa from 1978 to date reflects that South Africa has never drilled more than 25 offshore explorations wells per annum, yet the industry standard for regions such as the UK reflect that offshore exploration activity has never been below 25 exploration wells per annum. The maximum number of discoveries made during the same year, in South Africa was 5, in 1989, compared to the UK which made 28 discoveries in that same year[57]. The conclusion of this brief comparison of exploration activity is that, by international standards, South Africa's offshore geology is relatively unexplored. Furthermore, the magnitude of exploration activities correlates with the number of potential discoveries, namely the more exploration drilling that takes place the greater the likelihood of discoveries made.

Another factor to consider is the magnitude of offshore oil and gas field development in South Africa. An exploration well might be classified as a discovery, but the field might never be developed, as it is not commercially viable. A very limited proportion of exploration wells, drilled over the past three decades that have been classified as discoveries, have been considered commercially viable fields. Therefore, in addition to South Africa's geology being relatively unexplored, it is also underdeveloped. The lack of a suitable gas market or gas commercialisation strategy for South Africa has left some discoveries, that would otherwise be commercial, undeveloped, such as the Ibhubesi Gas Field[58].

Given that South Africa is not yet a significant producer of crude oil or natural gas, the fiscal terms (tax rules) are designed to attract investors to engage in exploration activities. In the situation of a significant discovery made in South Africa, the geological uncertainty will have reduced, paving the way for stricter fiscal terms.

## 9.1 OP26 mining leases

South Africa's investment regime for oil and gas exploration and production (prior to years of assessment commencing on or after 2 November 2006) was governed by the OP26 prospecting lease, OP26 mining lease and OP26 mining subleases, collectively known as

[57] Petroconsultants (UK) Ltd. (1992). *Evaluation of South African petroleum legislation; Comparative field economics and recent exploration performance is various countries.* Petroconsultants, Putney, London.
[58] Whilst there is a market for gas fired electricity generation in South Africa, small gas fields lack scale the required for viability.

“OP26”[59]. The OP26 leases were granted under the Minerals Act. OP26 contained tax incentives that overrode the ITA, including a tax stabilisation regime that “froze” the provisions of the Income Tax, as at 1977[60] .

SOEKOR (Pty) Limited (the state owned “Exploration and Production Company”) was granted, in 1967, the right, in terms of Prospecting Lease OP26, to prospect for natural hydrocarbons in the sea-bed and soil within the territorial waters and on the continental shelf of the Republic of South Africa, and, if a commercially viable discovery was made, to enter into a mining lease.

The OP26 prospecting lease grants SOEKOR the right to sub-let portions of the prospecting area (clause 15.1) and to enter into joint ventures (“JV”), partnerships and other forms of co-operation agreements in any portion of the prospecting area (clause 15.2), on such terms and conditions as the Minister of Minerals and Energy Affairs (“the Minister”) may approve. The OP26 prospecting lease provides that any sub-lease, JV arrangement, etc. will be subject to the same tax dispensation in relation to prospecting operations (clause 33) as well as in relation to any OP26 mining lease granted pursuant thereto (clause 23).

Transactions in connection with the OP26 prospecting lease and the OP26 prospecting sub-leases are taxed, based on the ITA as at 1977 (clause 33). Transactions in terms of the OP26 mining leases are taxable in accordance with the current provisions of ITA, subject to the following:

- in respect of deductions, the provisions of the ITA as at 1977 shall apply if they are more favourable than those of the current provisions; and
- certain other special tax consequences are also prescribed by the OP26 mining lease (clause 23).

The Prospecting Lease OP29 (“OP29 prospecting lease”), was also granted to SOEKOR in 1967. In terms of the OP29 prospecting lease, SOEKOR was granted the right to prospect for and develop commercially viable onshore discoveries. The OP29 prospecting lease was

[59] The taxation of oil and gas companies was in accordance with the OP26 leases until 2 Nov 2006 (with the inception of the 10th Schedule) even though the MPRDA came into effect in 2004 in relation to the issuance of exploration and production rights for oil and gas.
[60] Page 228 - Mitchell, L. (2007). Tenth Schedule. Income Tax reporter, 46(4): 228. Pietermartizburg: Lexis Nexis Tax Service.

relinquished by SOEKOR in 1992. As a result, the taxation of income from onshore exploration and production is taxed in accordance with the current provisions of the ITA

In 2002, MPRDA was promulgated. This Act proposes a departure from the existing oil and gas prospecting and mineral rights as contained in OP26. OP26 leases that were in existence prior to the promulgation of this Act were to continue in force until terminated or expired, or until June 2007, whichever occurred first.

In order to fill the vacuum created by the demise of the OP26, the National Treasury negotiated and finalised a new tax regime, partially based on that of OP26. This new tax regime is known as the "Tenth Schedule regime". Mitchell[61] notes that given the high risks and historically low rewards (in South Africa), if the key features of the OP26 regime were not renewed, few of the active companies would remain invested.

In addition to filling the void created by the demise of OP26, the Tenth Schedule to the ITA is designed to ensure greater transparency and standardization of the beneficial tax incentives applicable to the upstream oil and gas industry (in South Africa)[62].

## 9.2 Income tax act: s26B, Tenth Schedule, fiscal stability agreement

The Tenth Schedule regime came into operation on 2 November 2006 and applies to tax years of assessment commencing on or after 2 November 2006. Under the Tenth Schedule regime the taxation of oil and gas companies is no longer governed by the terms of the oil and gas right, but rather an oil and gas company is taxed in accordance with section 26B of the ITA. Anything not covered by the Tenth Schedule is taxed under the normal provisions of the Act, such as the anti-avoidance provisions and transfer pricing provisions.

Section 26B(1) of the ITA provides that the taxable income of any oil and gas company will be determined in accordance with the provisions of the ITA, subject to the specific provisions contained in the Tenth Schedule to the ITA, which contains reference to fiscal stability agreements.

[61] Page 228 – Mitchell, 2007
[62] Page 2 – Clegg & Steenkamp, 2007

In terms of section 26B(2) any tax payable on the net amount of any dividend declared by an oil and gas company as derived from profits attributable to its oil and gas income , must be determined in terms of the ITA but also subject to the provisions of the Tenth Schedule.

In terms of section 26B(3) the general anti-avoidance rule (as set out in Part IIA of Chapter 3) applies to the Tenth Schedule. The important features of the Tenth Schedule are:

### 9.2.1 Tax rate

The tax rate may not exceed 28 per cent, which is the normal tax rate on companies. Tax neutrality is a desirable feature of any tax system.

### 9.2.2 Dividend withholding tax

This is set at zero. This addresses the critical requirement of investors in large scale capital intensive projects, that they can recover their capital before paying taxes. Zero percent dividend withholding tax is consistent with the OP26 mining dispensation under the Minerals Act which preserved the taxation of oil and gas companies to a 1977 version of the ITA. In 1977 there were no dividend withholding taxes or secondary tax on companies ('STC').

This is a deviation from the usual dividends tax rate of 15%, which is subject to double taxation agreements that usually allow for 5%-10%. But zero percent withholding tax is consistent with a tax system aimed at equitable treatment of foreign and South African oil and gas companies. There is currently no branch profits remittance tax in South Africa. The introduction of dividend withholding tax in an environment where the corporate tax rate applied to foreign and South African oil and gas companies is the same would encourage the avoidance of dividend withholding tax by utilising branch holding structures for foreign companies[63]. Thus, it is recommended that the nil dividend tax provision be retained.

[63] Branch profits tax will only be possible where dealing with non-treaty countries. For treaty countries the non-discrimination clause would apply if branch profits tax applies. At present, none of the OPASA member companies operate through a branch structure.

### 9.2.3 Withholding tax on interest

The rate of withholding tax on interest is set at zero in relation to interest that is paid by an oil and gas company in respect of foreign loans, applied to fund exploration and post-exploration capital expenditure.

### 9.2.4 Recovery of capital expenditure

For any resource investor the most important way in which to provide for project risk is to be able to recover invested capital prior to the incidence of tax. This addresses the first requirement of any investor, namely that the capital invested should be returned within a reasonable time frame. The Tenth Schedule provides for this[64].

Operating expenditure is deductible in full at paragraph 5(1) of the Tenth Schedule: For the purposes of determining the taxable income of an oil and gas company during a year of assessment, there will be allowed as deductions from its oil and gas income all expenditure and losses actually incurred (other than any expenditure or loss actually incurred on the acquisition of an oil and gas right, except as allowed in paragraph 7(3)) in that year of exploration or production.

Capital expenditure on exploration or production is fully deductible, in terms of paragraph 5(1), but also qualifies for an "uplift" in terms of paragraph 5(2).

Thus, paragraph 5(2) of the Tenth Schedule allows for the additional deduction of 100% of the expenditure of a capital nature actually incurred in a year in respect of exploration, and it allows for the additional deduction of 50% of capital expenditure incurred in respect of production (post-exploration).

Essentially, as a consequence of paragraphs 5(1) and 5(2) together, oil and gas companies that incur capital expenditure in respect of exploration receive a 200% 'super deduction', and oil and gas companies that incur capital expenditure in respect of production receive a 150% 'super deduction'. No deduction may, however, be claimed in terms of paragraph 5(2) in respect of expenditure incurred for the acquisition of an oil and gas right. The IMF recommends a depletion allowance in relation to the acquisition of an oil and gas right but international research suggests that depletion allowances are typically not available in

[64] Mc Gregor, 2014

instances where ownership of mining rights (or custodianship as in the case of South Africa) vest in the State[65].

Mitchell[66] states that the "uplift" acts as an incentive to incur high-risk, high-cost capital expenditure that probably represents long-term sunken capital. Exploration is given a higher uplift due to the higher nature of the risk (and to compensate for the fact these losses will probably not be useable against income for a longer period than production expenses).

### 9.2.5 Disposal of an oil and gas right

If an oil and gas company disposes of (in full or in part) an oil and gas right to another company, the seller has the choice of two tax treatments, namely 'rollover treatment' or 'participation treatment'. If no election is made by the seller the disposal of the oil and gas right is recognised as a capital gain/loss, in accordance with the Eighth Schedule of the ITA, if the oil and tax right was held as a capital asset, or gross income/loss from the disposal of trading stock, if the right was acquired with the intention to resell it at a profit.

Where the seller has elected the rollover treatment, the seller does not recognise the capital gain/loss where the right was disposed of as a capital asset, or the gross income/loss where the right was disposed of as trading stock. Where the oil and gas right was held as a capital asset by the seller, the consideration paid by the purchaser is disregarded for tax purposes, and the purchaser is treated as having acquired the oil and gas right at a cost equal to the base cost of the oil and gas right in the seller's hands. Where the oil and gas right was held with a speculative intent by the seller, the consideration paid by the purchaser is disregarded for tax purposes and the purchaser is treated as having acquired the oil and gas right at its cost to the seller.

The participation treatment may be elected by the seller when the seller disposes of the oil and gas right at a market value that exceeds the base cost of the oil and tax right (if the oil and gas right was held as a capital asset) or exceeds the lower of the realisable cost or opening balance of the oil and gas right (if the oil and gas right was held as trading stock). When the seller makes a participation election, the seller recognises the proceeds on the sale of the oil and gas right as gross income, and the purchaser may deduct the consideration paid from its oil and gas income.

[65] Page 12 – Mining Report, 2015
[66] Page 82 – Mitchell, 2007

### 9.2.6 Fiscal stability

Sunley et al.[67] indicates that given the nature of investment in oil and gas extraction (namely: long term, large-scale and up-front) a particular concern for investors is to guard themselves against unforeseen changes to the financial premises of the project. One safeguard mechanism that is often sought by investors is the inclusion of a stability clause in the project agreement.

Stability clauses are in alignment with international practice. Stability clauses are widespread in the oil and gas sector. Of 109 countries surveyed in 1997, by Barrows[68], a majority (63 per cent) provided stability clauses. A small group (14 per cent) had partial stability clauses excluding income tax. Finally, a minority (23 per cent) did not provide any stability clauses, in license/concession agreements (at least up until 1997). However, this does not prevent an investor from seeking to renegotiate terms in response to policy changes. A recent example of a country, which repealed its stability clause for contracts signed from 2002 onwards, is that of Kazakhstan. Terms and conditions set in contracts may now be adjusted in compliance with amendments to legislation, by the mutual consent of the government and the contractor[69].

The Tenth Schedule of the ITA, at paragraph 8, gives the South African Minister of Finance, after consultation with the Minister of Minerals and Energy, the power to enter into fiscal stability agreements when an oil and gas company receives an MPRDA oil and gas right. These agreements provide a guarantee that the provisions of the Tenth Schedule, as at the date of the agreement, will continue to apply for the duration of the company's oil and gas right.

The fiscal stability agreement will remain in place over the full life of the oil and gas right, and also if exploration rights are renewed or converted to production rights.

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[67] Page 8 - Sunley, E.M., Baunsgaard, T. & Simard, D. (2002). Revenue from the Oil and Gas Sector: Issues and Country Experience. Paper prepared for IMF Conference on fiscal policy formulation in oil producing countries. Washington: World Bank and International Finance Corporation.
[68] Barrows,G.(1997) *World Fiscal Systems for Oil*, The Barrows Company Inc
[69] Page, W. (2002) *"Kazakhstan's New Tax Code"*, Tax Notes International, January 21, 2002.

An oil and gas company may at any time, unilaterally, rescind the agreements if so desired (that is, if subsequent tax law becomes even more favourable than this regime).

The fiscal stability agreement under the Tenth Schedule is not to be confused with a Bi-lateral Investment Treaty (BIT). The fiscal stability agreement differs from a BIT in terms of its parties, scope and duration. The differences between these two types of agreements, in the South African context, are set out in the table below:

| | SA Fiscal Stability Agreement | Typical SA Bi-lateral Investment Treaty |
|---|---|---|
| **Parties** | State and MPRDA right holder | Two States on behalf of their residents |
| **Scope** | Preservation of the provisions of the Tenth Schedule as deals with the corporate taxation of an oil and gas company | 1) protection from expropriation or nationalisation,<br>2) most favoured nation treatment, which entails treatment no less favourable than that accorded to other foreign investors in like circumstances,<br>3) national treatment, being treatment no less favourable in similar circumstances compared to treatment of nationals of the home state,<br>4) repatriation and investment of earnings,<br>5) observation of contractual obligations, and<br>6) dispute resolution |
| **Duration of Stability** | Duration of MPRDA right – 39yrs max | 10 to 20 years |
| **Number of agreements** | 10 | 42 remaining |

In 2007, Italian investors filed a claim against South Africa under the ICSID Additional Facility Rules, arguing that the entry into force of the Mineral and Petroleum Resources Development Act (MPRDA) effectively expropriated the investors' mineral rights and, accordingly, breached the protections contained in both the Italy – South Africa BIT and the separate BIT between South Africa and Belgium and Luxembourg, which their Luxembourg-based holding company was subject to. The investors argued that these expropriations were unlawful, not only because there was insufficient compensation, but also because of a failure of due process. The investors alleged that the BEE provisions of the MPRDA amounted to expropriation of their mineral rights. The claim was settled, but perhaps prompted by this case, South Africa soon began a review of its BITs.

In 2010 South Africa concluded its review of its bilateral investment treaty policy framework, and from October 2012 South Africa began giving notice to terminate its bi-lateral investment treaties (BITS) with various countries, such as Switzerland, Netherlands, Spain, Luxembourg and Belgium and Germany. South Africa is shifting away from the use of BITS toward domestic regulation in the form of the Promotion and Protection of Investment Bill of 2013.

## 9.3 Royalty regime

The MPRRA became effective from 1 March 2010. It was created by statute, being the MPRDA, which requires all extractors of South Africa's non-renewable mineral resources to pay a levy (royalty) to the state for its exploitation. The Royalty, in the context of oil and gas, is imposed on an oil and gas company, as defined.

The Royalty calculation is based on a variable royalty percentage rate, which would depend, inter alia, on whether the mineral resource is transferred as:

- Refined – refined mineral resources are those that have undergone a comprehensive level of beneficiation (e.g. smelting and refining). Schedule I to the MPRRA lists minerals in their refined condition
- Unrefined – unrefined mineral resources are those that have undergone limited beneficiation (some processing). Schedule II to the MPRRA lists minerals in their unrefined condition

Oil and gas companies are included under the “refined” royalty percentage rate formula regime in order to ensure a lower royalty percentage rate structure. This lower percentage is accepted due to the limited likelihood of finding significant oil and gas in South Africa, onshore or offshore with the resulting higher levels of exploration and production expenditures.

| |
|---|
| The percentage Rate for refined minerals is determined as follows: |
| 0.5 + [Earnings before interest and taxes / (gross sales iro refined minerals x 12.5)] |

Capped at a maximum of 5%[70]

The Royalty is examined in detail in the Mining Report. The Royalty was carefully designed to achieve a strong balance of ensuring that it is responsive to different economic circumstances, capturing rents when profits are high, and ensuring a measure of cover (for the *fiscus*) in the form of a minimum revenue stream, during weak economic cycles and low commodity prices. Accordingly, the Mining Report recommends, broadly, to maintain the royalty regime, whilst recognising that various aspects of the royalty regime still need to be clarified and improved, particularly in relation to determination of the gross sales tax base. At this stage, the Davis Committee has not yet made detailed recommendations on this issue, but will attempt to do so in a later version of the Mining Report. In this Report, (namely. the Oil and Gas Report) the Davis Tax Committee recommends a move away from the formula used to derive the rate of royalty, to a fixed rate royalty of 5% of gross sales in the context of the production of oil and gas from MPRDA rights.

## 9.4 Customs and excise duty relief

Under the Customs and Excise Act, Act No 91 of 1964, equipment, machinery, materials, instruments, supplies and accessories utilised in the exploration of oil and gas imported under rebate item 460.23 are exempt from customs duty[71] and value added tax (VAT).

[70] Olivier, G. (2014). Presentation to Davis Tax Committee: Offshore Oil and Gas Industry of South Africa, Pretoria, South Africa.

[71] Page 31 – Futter, A.J. (2010) *The Taxation of Oil and Gas Exploration and Production in South Africa.* Dissertation submitted in fulfilment of the requirements for the degree of Master of Commerce: Taxation in the Department of Accounting, University of Cape Town.

In relation to diesel consumed for offshore mining, a refund of the Fuel Levy and Road Accident Fund (RAF) Levy is allowed under section 75(1A) , read with item 670.04 of Schedule 6 to the Customs and Excise Act, Act No 91 of 1964. With Effect from 1 April 2016, the total diesel refund allowed is R4.24/litre.

## 9.5 International benchmarking of tax systems

The international taxation of the exploration for, and production of, oil and gas is complex and dynamic. Each year between 25-50 countries in the world offer license rounds; 20-30 countries introduce new model contracts or fiscal regimes; and nearly all countries revise their tax laws during their annual budgetary process[72]. There are more tax systems in the world than there are countries because numerous vintages of petroleum licensing contracts may be in force at any one time, countries typically use more than one arrangement, and contract's tax terms are often negotiated and renegotiated as political and economic conditions change, or as better information becomes available[73] .

According to Wood[74] the key objectives of the fiscal design are:

1. Divide economic rent appropriately.
2. Ensure efficient and environmentally appropriate development of resources.
3. Promote investment of both development and risk capital.
4. Provide a mechanism for cost recovery that does not penalise commerciality (namely, provide a producer with a reasonable return on any investments, made in a realistic timeframe).
5. Create a flexible regime that responds effectively to changing market conditions and projects of varying size, cost and risk.
6. Establish transparent fiscal instruments that can be easily administered, audited and widely understood.

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[72] Page 1 - Kaiser, M.J. & Pulsipher, A.G. (2004). Fiscal System Analysis: Concessionary and Contractual Systems Used in Offshore Petroleum Arrangements. Louisiana: Coastal Marine Institute.
[73] Page 5 - Johnston, D. (2002). "Current developments in production sharing contracts and international concerns: Retrospective government take – not a perfect statistic." Petroleum Accounting and Financial Management Journal. 21(2):101-108.
[74] Page 65 - Wood, D. (2008). Preliminary Report on Fiscal Designs for the Development of Alaska Natural Gas. Report for the State of Alaska Legislative Budget & Audit Committee. David Wood & Associates, Alberta, Canada.

7. Promote competition among those willing to invest in exploration, field development and infrastructure construction. This may not be a universal objective, as in certain countries monopoly resource holders, or infrastructure operators, may be given preferential rights.

These objectives can be achieved in a variety of fiscal designs, but two quite distinct generic legal designs have evolved that are widely employed, in a variety of forms, by countries around the world. These are:

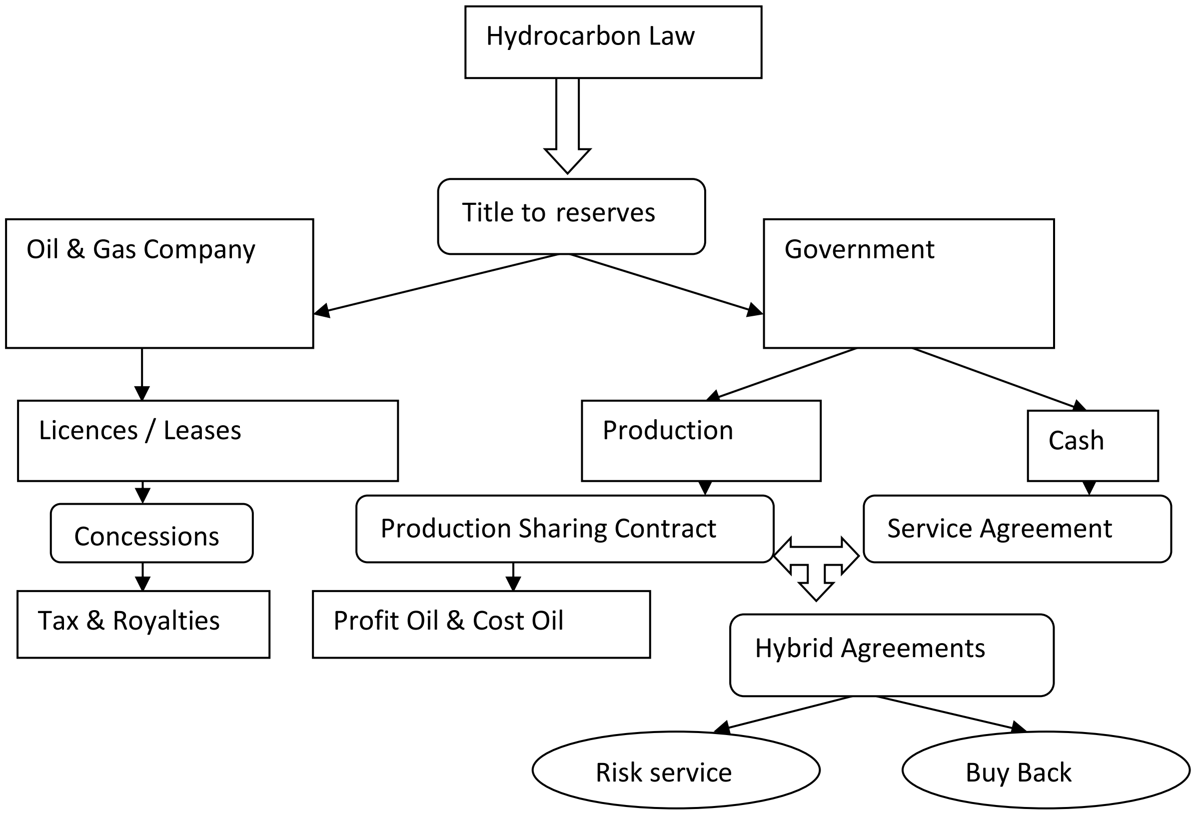
(i) Concessions (also called licenses or tax/royalty systems); and

(ii) Contracts:

a. Production sharing contracts (PSCs) (also called production sharing agreements); and

b. Service agreements (SAs)

Although these arrangements are conceptually different from each other, particularly in terms of levels of control exercised by the government, ownership rights, and compensation arrangements, they can be used to accomplish the same purpose [75].




[75] Page 8 - Tordo, S. (2009). Countries' Experience with the Allocation of Petroleum Exploration and Production Rights: Strategies and Design Issues. Washington: The World Bank Group.

The fundamental legal designs for Oil and Gas[76]

### 9.5.1 Concessions

Concessions originated in the silver mining operations of Greece in 480 BC[77], and are maintained and favoured by most OECD governments, and many other developed countries where the governments usually hold mineral rights[78].

A concession grants an exclusive license to a qualified investor. Usually, licenses are granted by a government authority on behalf of the host country. Certain petroleum regimes recognise the owner of the land as the owner of the subsoil, and allow it to grant licenses within the context of existing legislation (for example the United States Onshore). Historically, oil and gas mineral rights were granted by concession[79]. The original concession (i) granted rights to petroleum development over a vast area; (ii) had a relatively long duration; (iii) granted extensive control over the schedule and manner in which petroleum reserves were developed to the investor; and (iv) reserved few rights for the country, except the right to receive a payment based on production. The provisions of modern concession agreements differ from the original model. In addition to reducing the area coverage and the duration of the agreement, modern concessions also contain relinquishment clauses and express obligations to enter into a work program[80].

One of the main characteristics of concessions is that the state retains considerable liberty to modify, at any time, those terms and conditions that are not negotiated but fixed by legislation. In practice, because a stable investment environment is important to encourage or maintain investments by private companies, states are motivated not to abuse this prerogative[81].

[76] Adapted from Wood, 2008:64
[77] Page 611 - Anderson, O.L. 1998. "Royalty valuation: Should royalty obligations be determined intrinsically, theoretically, or realistically?" Natural Resources Law Journal. 37:611.
[78] Page 65 – Wood, 2008
[79] In South Africa, onshore mineral rights were originally linked to land ownership until 2004
[80] Page 9 – Tordo, 2009
[81] Page 9 – Tordo, 2009

A concession grants the oil and gas company (or a consortium) the exclusive right to explore for and produce hydrocarbons within a specific area (called the *license area, block,* or *tract,* depending on local laws) for a given time. The company assumes all risks and costs associated with the exploration, development, and production of petroleum in the area covered by concession. Often a license fee or bonus is paid to the government[82].

The government's compensation for the use of the resource, by the oil and gas company, will typically include royalty and tax payments if hydrocarbons are produced.

Nearly half of the countries worldwide use a concession-type regime. Concession-type regimes are used, for example, in the United States Offshore, United Kingdom, France, Norway, Ireland, Spain, Portugal, Chad, Australia, Russia, New Zealand, Colombia, South Africa, and Argentina[83]. Across this group of countries, there is considerable diversity of fiscal arrangements. The fiscal instruments applied to such systems include royalties, special petroleum taxes (levied on production or profits), property taxes (levied on onshore facilities) and corporate taxes levied on income. The rates of royalties and taxes are frequently linked to other metrics that trigger specific rates and increase flexibility. Bid bonus payments to secure leases through competitive tender also constitute an important component of the income accruing to governments under such systems[84].

| | | |
|---|---|---|
| (Gross Income)Production Value | | 2000 |
| *Less* | Royalties | 100 (5% of production value or volumes) |
| *Less* | Allowable Deductions | 400 (Operating Costs, finance cost etc.) |
| *Less* | Capital Allowances | <u>600</u> (Depreciation of capital expenditure) |
| Taxable Income | | 900 |
| Corporate Income Taxes | | 252 (28% of taxable income) |

Illustration: Structure of the Concessionary System – Fiscal Regime

| | | |
|---|---|---|
| | Production Value | 2000 |
| *Less* | Total Costs | <u>1000</u> |
| | Total Profit | 1000 |

82 Page 9 – Tordo, 2009
83 Page 10 – Tordo, 2009
84 Page 65 – Wood, 2008

| | |
|---|---|
| Royalties (5%) | 100 |
| Taxes (28%) | 252 |
| Contractor take | 648 |
| | |
| Contractor take | 64.8% (648 / 1000) |
| Government take | 35.2% |

Illustration Structure of the Concessionary System: – Government & Contractor Take

Under a concession, the ownership of petroleum in *situ* remains with the host government, until and unless petroleum is produced and reaches the wellhead, at which point it passes to the oil and gas company. The oil and gas company is not exposed to changes in its reserves and production entitlements when the oil price changes. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for the exploration for and production of hydrocarbons generally passes to the host government at the expiry or termination of the concession (whichever is earlier), and the oil and gas company is typically responsible for abandonment and site restoration[85] .

### 9.5.2 Production sharing contracts

PSC are favoured by many developing countries. Since the first one was signed by the Independent Indonesian American Petroleum Company (IIAPCO) in August 1966 with Permina (now Pertamina), the NOC of the government of Indonesia, these have become popular with developing nations because they retain title to reserves and are able to share in the revenues from risk investments without taking the financial risks[86]. They are not however embraced by all developing nations. Several OPEC countries refuse to entertain them (for example Saudi Arabia, Kuwait and Iran) and a fierce debate ensued in Russia, which adopted a few PSCs in the 1990s (e.g. Sakhalin-I and II), but President Putin essentially rejected them in 2004 in favour of a tax system that enables the government to more easily adjust (generally upwards) its take and control of large industry projects of strategic interest in line with market conditions[87] .

PSCs involve contractual agreements concluded between one or more oil and gas companies (contractors) and a state party. The state party may be the state itself, represented by its

[85] Page 10 – Tordo, 2009
[86] Page 66 – Wood, 2008
[87] Page 68 – Wood, 2008

government, or a state authority (such as a government ministry or a special department or agency) or the NOC. The NOC may be granted general authority to engage in petroleum operations or the sole right to receive an exclusive license, and the authority to engage the assistance of oil companies[88].

Like a concession, a PSC grants an oil and gas company or consortium (the contractor) the right to explore for and produce hydrocarbons within a specified area and for a limited time period. The contractor assumes all exploration risks and costs in exchange for a share of petroleum produced from the contract area[89]. The fiscal mechanisms that determine how production is shared vary significantly from country to country, but usually involve distinctive elements relating to profit and to cost recovery. These are known as cost oil and profit oil respectively:

(i) Cost oil is expressed as a fixed percentage of production revenue and is made available for recovery of capital costs (with or without uplift), operating costs and exploration costs. The cost recovery ceiling varies enormously around the world and reducing its cap guarantees the host government an earlier share of revenues. It is common to have a 50% ceiling placed on a proportion of quarterly production for reimbursement of these costs. There are different categories of depreciation schedules which are applied to cost recovery, with potentially full depreciation of intangible exploration and drilling costs in the year incurred, while the tangible development costs being typically recovered over 5 years on a straight line basis. In terms of marginal field development, the more quickly costs are recovered the less likely are possibilities of marginal developments being deterred[90] .

(ii) Remaining oil production after cost oil deductions, is considered profit oil and is split between the host government and the contractor per a predefined, negotiated percentage. Naturally the terms negotiated in the cost oil recovery, discussed above, will determine how soon and to what

[88] Page 10 – Tordo, 2009
[89] Page 10 – Tordo, 2009
[90] Page 6 - Farnejad, H (2007). ‘How Competitive is the Iranian Buy-Back Contracts in Comparison to Contractual Production Sharing Fiscal Systems?’. 7(1): Oil and Gas Energy.

magnitude the profit oil becomes available for the two parties to share. The original production sharing schemes in Indonesia had a flat-rate split on profit oil and gas, however, the more recent contracts are frequently based on a progressive or incremental basis, with the state share increasing with annual production[91].

The profit oil can be shared in any (or a combination) of the following ways [92]:

- *Fixed Share*. Although PSCs of this nature share profits between the state and the contractor, in reality, because the allocation of profit oil is fixed, they have much in common with tax and royalty arrangements. Examples of a fixed-share PSC include many of those written in Indonesia.
- *Production Rate*. These contracts generally tend to be written around cumulative production, with changes in total oil or gas produced driving the change in allocation (for example Nigeria Deepwater, Malaysian offshore and Egypt). In some cases they may, however, be based on the absolute volume of daily production planned (for example Qatar).
- *R-Factor*. This is a negotiated figure set on the basis of the indicated ratios of cumulative revenues over the cumulative investment costs incurred. Examples of countries that tend towards R-factor based contracts include Yemen, Qatar and Libya.
- *Internal rate of return ("IRR")*. This scheme is very flexible to variations in profitability from all sources, namely (a) oil/gas price movements, (b) variations in field sizes, and (c) variations in investment costs. IRR based contracts are structured such that, depending upon the internal rate of return that the project has achieved, the share of profit oil barrels will alter. As with most PSCs, they typically allocate a higher share of revenues to the contractor through the early phases of a project, but a greater share to the state as the contractors' capital is recouped and the rate of return on the project rises. Indeed, as their name suggests, changes in the allocation of barrels between state and contractor

[91] Page 7 – Farnejad, 2007
[92] Page 114 - Herrmann,L, Dunphy, E & Copus, J. (2010) Oil and Gas for Beginner, London: Deutsche Bank AG.

(trigger points) tend to be associated with the achievement of different internal rates of return. Countries which commonly use IRR-based contracts as a mechanism for determining share include Angola, Russia, Kazakhstan, and Azerbaijan, amongst others.

Royalties can also be introduced into the production sharing regime. In some PSCs there is an explicit royalty payment that is paid to the host government before the remaining production is split between cost and profit oil. An alternative to a royalty is to have a limit on cost oil, which ensures there is profit oil, as soon as production commences. Where a cap is imposed on the deduction of costs and costs are at this limit, the cap will have a similar economic impact as a royalty, with the government receiving revenue, its share of profit oil, as soon as production commences[93].

Unrecovered costs in any year are carried forward to subsequent years, but some PSCs allow these costs to be uplifted by an interest factor to compensate for the delay in cost recovery. Interest expenses are generally not a recoverable cost. If interest expenses are allowed to be recovered, then there should be no uplift for unrecovered costs, as this would involve a double counting to the extent unrecovered costs are debt financed[94].

| | | |
|---|---|---|
| (Gross Income)Production Value | | 2000 |
| *Less* | Royalties | 100 (5% of production value or volumes) |
| *Less* | Total Cost recovery | 1000 (Interest, operating costs, depreciation, depletion & amortization) |
| Profit Oil | | 900 |
| Government share | | 540 (60% of profit oil) |
| Contractor share (Taxable Income) | | 360 (40% of profit oil) |
| Corporate Tax/Resource Rent | | 90 (25% of contractor share) |

Illustration: Structure of the Production Sharing Contract System: – Fiscal Regime

| | | |
|---|---|---|
| | Production Value | 2000 |
| *Less* | Total Cost Oil | 1000 |
| | Total Profit | 1000 |
| | Government Share | 540 |
| | Royalty (5%) | 100 |

[93] Page 7 – Sunley et al, 2002
[94] Page 7 – Sunley et al, 2002

| | |
|---|---|
| Taxes ( 25%) | 90 |
| Contractor take | 270 |
| | |
| Contractor take | 27% (270 /1000) |
| Government take | 73% |

Illustration: Structure of the Production Sharing Contract: – Government & Contractor Take

Most PSCs involve exploration and production phases (exploration and production sharing agreements, called EPSAs), but some (for example Qatar) are signed to cover development of already discovered reserves (development and production sharing agreements, called DPSAs). Some PSCs attempt to achieve fiscal stability by either allocating tax and royalty payments to be made only from the government's share of production, or including a fiscal stability clause. A signature bonus, which can in some cases amount to several hundred million dollars, is usually paid by the contractor to the government on the effective (signature) date of the PSC[95].

Unlike a concession, a PSC provides the oil and gas company with the ownership of its share of production only at the delivery point or export point (as defined in the contract). Changes in the oil and gas price result in adjustments to the oil and gas company's share of reserves and production entitlement. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons, generally passes to the State, usually upon commissioning. In some countries, such as Nigeria, title transfers before commissioning; that is, when equipment arrives in the country. In some countries, title transfers to the government upon pay-out, when the oil and gas company has recovered its investment or the equipment is fully amortized. Furthermore, unless specific provisions have been included in the contract (or in the relevant legislation), the government (or the national oil company) is typically legally responsible for abandonment[96] .

<u>The IMF recommends a move toward a PSC regime as one of three options to deal with the uncertainty of State Participation[97].</u>

[95] Page 66 – Wood, 2008
[96] Page 10 – Tordo, 2009
[97] Page 58- Daniel, P., Grote, M., Harris,P. & Shah, A., 2015

### 9.5.3 Service agreements

Under a Service Agreement, the host government hires the oil and gas company (contractor) to perform exploration and/or production services within a specified area, for a specific time period. Contractor services are compensated by a fixed or variable fee. The host government maintains ownership of petroleum at all times, whether *in situ* or produced. The contractor does not acquire any ownership rights to petroleum, except where the contract stipulates the right of the contractor to be paid its fee in kind (with oil and/or gas) or grants a preferential right to the contractor to purchase part of the production from the government. Most industry Service Agreements contain elements of risk for the contractor.

Not all countries operate just one or other of these types of fiscal systems for the taxation of the exploration for, and production of, oil and gas nor do they stick rigidly to one set of rates for the fiscal instruments applied as new contracts or leases are awarded to industry participants. In Nigeria, for example, projects operating under the first three of the system types, identified above, are active. Moreover, countries may operate several contracts with different PSC mechanisms for historical, geographic or variable risk or cost reasons [98]

In South Africa, it is interesting to observe that the Tenth Schedule accommodates the use of Service Agreements, in that it recognizes an 'oil and gas company' as defined for purposes of the Tenth Schedule to include not only the oil and gas rights holder, but also a contractor who engages in exploration or post-exploration, in terms of any MPRDA oil and gas right.

### 9.5.4 Risk Service

A risk-service contract is similar to the PSC arrangement. Risk-Service contracts are based on a simple formula: The oil and gas company will fund all investment costs and implement exploration and/or production operations on behalf of the host government owned NOC, per an agreed scope of work. In return, if exploration efforts are successful, the oil and gas company will receive remuneration for advances on these investment funds, operating costs, related bank charges with interest and the negotiated rate of return through the

[98] Page 67 – Wood, 2008

NOC's allocation of production. According to Johnston[99], the net importing countries are the ones most likely to use a risk-service contract. Risk service agreements are used in Chile, Ecuador, Iraq and the Philippines. In Peru and Ivory Coast either the risk service contract or a concession could be used.

### 9.5.6 Buy back

Buy back agreements are similar to engineering, procurement, and construction contracts. Buy back agreements are the least favoured by the oil and gas companies, because they are engaged to perform development work on a financial fee basis (cost plus an agreed rate of return), without the opportunity to share in the upside revenues from long-term field production[100].

The oil and gas company bears the risk of cost overruns (financial risk) and exploration risk (technical risk). The oil and gas company's long-term participation in successful ventures is severely limited as their entitlements cease once the contractually agreed rate of return is achieved (for example Iran's buy-back contracts). Moreover, operatorship usually reverts to the NOC once the field or facility has come on-stream, and failure to achieve the projected levels of production within the contracted timeframe will also impede the oil and gas company's rate of return or pay-out[101].

## 9.6 Problems with the SA tax system for Oil and Gas, and possible solutions

### 9.6.1 Transferability of fiscal stability

In relation to the disposal of a production right, the Tenth Schedule to the ITA, at paragraph 8(2)(b), limits the transfer of Tenth Schedule fiscal stability agreement rights to any other oil and gas company.

South Africa competes with other destinations for new entrants into the oil and gas industry. South Africa's poor geological attractiveness of producing assets may deter a new entrant. This coupled with the fact that the new entrant does not enter on a level playing field to

[99] Page 87 – Johnston, 1994
[100] Page 66 – Wood, 2008
[101] Page 66 – Wood, 2008

existing participants, may further deter new entrants. True fiscal stability is assurance that the legislative treatment is stable, predictable and uniform to all participants.

The Tenth Schedule to the ITA is described as having been negotiated and finalised by National Treasury in order to address the MPRDA and OP26 regime. Given the high risks, and historically low rewards (in this industry in South Africa), the Tenth Schedule was premised on the OP26 regime to encourage the few active companies in this industry to remain invested.

The OP26 regime allowed an oil and gas company to transfer all or part of its rights, duties and obligations under the lease to any other oil and gas company, this includes fiscal stability in relation to the mining lease.

The Tenth Schedule at paragraph 8 provides for the transfer of the fiscal stability agreement rights in relation to:

- Disposals of exploration rights (paragraph 8(2)(a));
- Disposals within the same group (paragraph 8(2)(b));
- Sharing of fiscal stability agreement rights in relation to jointly held Exploration Rights (paragraph 8(1)(c) (with effect from 1 April 2015);
- Changes in participating interest percentage (paragraph 8(3)).

In the spirit of alignment with the OP26 regime, in relation to the Tenth Schedule, it is recommended that stability agreement rights, on disposal of an oil and gas right to any other oil and gas companies, be extended to production rights.

It should be noted that projects that have survived to development stage are not entirely risk free, and require significant cash outlay for the development stage. Furthermore, a new entrant comes in on basement terms, namely the new entrant pays only the back-costs.

*Business context*

Changes to the participants in an oil and gas right are not uncommon at production stage. These changes are not driven by profits that may be realised on disposal. These changes are driven by:

1. A participant’s intention to refocus its activities and resources to better producing opportunities (often outside South Africa);
2. Increases in operating costs that can no longer be afforded;
3. Decisions to invest in further capital to enhance recovery that cannot be afforded by all participants;
4. A participant choosing to reduce the investment risk where the economic returns do not warrant further expenditure;
5. A participant’s realignment of its core business (typical for companies focused on exploration and not production). In such instances, participation in a producing asset will be sold out to a company specialising in production.

The transferability of these fiscal stability agreement rights impacts on the marketability of a production right. Any new participant to a production right will not currently share the fiscal stability enjoyed by original participants. Accordingly, the new participant will not operate on an equal footing to its partners.

This inequity can also influence the decision-making of a joint venture after a new participant’s entry, for example, where the economics of further investment to enhance recovery proves to be unviable for one of the participants because of a difference in fiscal treatment.

*Proposed solution*

The DTC’s proposed solution is that sub-paragraph (1)(c) of paragraph 8 of the Tenth Schedule be amended as follows:

‘‘(c) If an oil and gas company jointly holds, with another oil and gas company, an oil and gas right, and any one of those oil and gas companies has concluded an agreement, as contemplated in subparagraph (1,) in respect of that right, all of the fiscal stability rights in terms of that agreement, relating to that oil and gas right, apply in respect of both of those companies.’’

Sub-paragraph (2)(a) and paragraph (2)(b) of paragraph 8 of the Tenth Schedule be substituted with the following sub-paragraph:

"8(2) In the case of a disposal of an oil and gas right as defined in sub-paragraph (7) an oil and gas company that has concluded an agreement as contemplated in subparagraph (1) in respect of that right may, as part of that disposal, assign all of its fiscal stability rights in terms of that agreement relating to the oil and gas right disposed of, to any acquiring company."

The suggested wording consolidates exploration and production rights to the defined term 'oil and gas right' in sub-paragraph 8(7) of the Tenth Schedule and, correspondingly, eliminates the distinction in relation to the assignment of such fiscal stability agreement rights on disposal to any acquiring company.

The term 'acquiring company' has been used in the proposed wording in substitution for 'other oil and gas company'. An oil and gas company is defined, in paragraph 1 of the Tenth Schedule, as a company that holds any oil and gas right. This definition prejudices new entrants that do not hold an existing oil and gas right. Although, it may be argued that, upon acquiring a participation in a production right, the new entrant simultaneously becomes an oil and gas company as defined and, accordingly, becomes a company to which the rights under a fiscal stability agreement may be transferred.

To accommodate those oil and gas rights holders that have already negotiated and signed Fiscal Stability Agreements as envisage in paragraph 8(1)(a) and paragraph 8(1)(b) of the Tenth Schedule, it is proposed that this amendment is deemed to come into operation on 30 October 2007 and are applicable to any agreement entered into on or after that date.

### 9.6.2 Preservation of fiscal stability

The Tenth Schedule to the ITA makes provision for oil and gas companies to enter fiscal stability agreements. However such fiscal stability agreements guarantee only the provisions of the Tenth Schedule as at the date of the agreement. Such an agreement:

1. Does not encompass all taxes levied on an oil and gas company;
2. Does not prevent the introduction of new taxes in relation to an oil and gas company; and.
3. Does not prevent amendments in the body of the ITA, targeted specifically at oil and gas companies.

*Proposed solution*

It is proposed by the DTC that an additional sub-section to Section 26B is inserted, that reads as follows:

"(3) No provision of this Act, applicable solely to an oil and gas company, as defined in the Tenth Schedule, shall be of any force and effect unless contained in that schedule".

The suggested wording provides assurance to oil and gas companies that there would be no possibility of oil and gas targeted measures being brought in 'through the back door' i.e. elsewhere in the ITA, eroding fiscal stability under the Tenth Schedule.

### 9.6.3 Definition of an oil and gas company

The MPRDA, requires the participation of Historically Disadvantaged South Africans (HDSA) in the issuance of Exploration and Production Rights. In accordance with proposed amendments to the Mining Charter, the allocation toward BEE participation, in oil and gas rights, is 10%.

The Tenth Schedule to the ITA applies to an oil and gas company as defined and excludes oil and gas rights holders which are not incorporated in the legal form of a company.

*Proposed solution*

It is proposed by the DTC[102] that the definition of 'oil and gas company' in the Tenth Schedule to the ITA be replaced with a definition of 'oil and gas rights holder', and the correspondent replacement of all references to 'oil and gas company' with 'oil and gas rights holder' in the Tenth Schedule, and 'company' with 'person', respectively.

The proposed definition of oil and gas rights holder is as follows:

"oil and gas rights holder" means any person that –

(i) holds any oil and gas right; or

(ii) engages in the exploration or post-exploration in terms of any oil and gas right".

[102] Lunn, S. (2014). *Proposal: Annexure A: Income Tax – Domestic Business – Tenth Schedule Amendments*. OPASA response to National Treasury request to submit technical proposals. 12 Dec 2014

The suggested wording accommodates the inclusion of HDSA rights holders in the Tenth Schedule, irrespective of the legal form of their participation in an oil and gas right.

### 9.6.4 Disposal of shares in an oil and gas company

Non-residents are subject to Capital Gains Tax on the disposal of immovable property situated in the Republic held by that person, or any interest or right of whatever nature, of that person, to or in immovable property situated in the Republic, including rights to variable or fixed payments as consideration for the working of, or the right to work mineral deposits, sources and other natural resources[103]. But there is no capital gains tax when a non-resident disposes of shares in an oil and gas company. The paragraph in the Eighth Schedule which is intended to deal with the disposal of shares by a non-resident is limited in its application to the disposal of shares in a company where 80% or more of the market value of those equity shares is attributable directly or indirectly to immovable property. A mineral right is not immovable property (corporeal asset)[104]for purpose of the Eighth Schedule.

*Proposed solution*

It is proposed by the DTC that the ambit of paragraph 2(1)(*a*) of the Eighth Schedule to the ITA is extended by the following insertion:-

"(2) For purposes of subparagraph (1)(*b*)(i), an interest in immovable property situated in the Republic includes any equity shares held by a person in a company or ownership or right to ownership of a person in any other entity or a vested interest of a person in any assets of any trust, if-

> (*a*) 80 per cent or more of the market value of those equity shares, ownership or right to ownership or vested interest, as the case may be, at the time of disposal thereof is attributable directly or indirectly to immovable property <u>including rights to variable or fixed payments as consideration for the working of, or the right to work mineral deposits, sources and other natural resources held otherwise than as trading stock; and…"</u>

[103] Paragraph 2(1)(*b*)(i) of the Eighth Schedule to the ITA

[104] Govender, P. (2014) *Does a mineral right constitute 'immovable property' for purposes of the Income Tax Act and double tax treaties?* Minor dissertation presented in partial fulfilment of the requirements for the Degree of Master of Law in Taxation, University of Cape Town.

Where a non-resident holds the shares in an oil and gas company as a capital asset, the suggested wording will subject the disposal of such shares to Capital Gains Tax.

### 9.6.5 Rehabilitation Company and Trusts

Two statutes govern Environmental Financial Provisions. These are the Mineral and Petroleum Resources Development Act (MPRDA) No 28, of 2002, and the National Environmental Management Act (NEMA) No 107, of 1998. In accordance with section 41 of the MPRDA, one or more of the following methods were acceptable forms of financial provision for abandonment and rehabilitation in relation to a MPRDA right:

- Approved contributions to a dedicated trust fund or section 21 company as provided for in section 37A of the ITA. (Contributions to such a fund as well as any profit or gains of the fund are exempt from tax);
- A written guarantee from a bank, other approved financial institution, statutory body or provincial or municipal authority guaranteeing the availability of funds if the mining company should fail or become incapacitated;
- A deposit into the account specified by the Director-General of the Department of Mineral Resources in the format as approved by the Director-General from time to time; or
- Other financial provision approved by the Director-General of the Department of Minerals Resources on an ad hoc basis, if the above methods should, in a specific case, prove to be impractical.

  In this regard other financial provisions included insurance policies, or parent company guarantees where the balance sheet of the holding company supports such guarantees.

In terms of section 24P of the NEMA, all applicants for an environmental authorisation relating to prospecting, mining, exploration, production or related activities on a prospecting, mining, exploration or production area, must make the prescribed financial provision for the rehabilitation, management and closure of environmental impacts, before the Minister of Minerals Resources issues the environmental authorisation. The forms of financial provision for abandonment and rehabilitation provided for in the NEMA regulations released on 20 November 2015, are limited to:

(i) financial guarantee from a bank or from a financial institution such as an insurer or underwriter;

(ii) a deposit into an account administered by the Minister responsible for mineral resources; or

(iii) a trust fund to be administered in respect of latent or unforeseen liability only.

The NEMA regulations are cause for concern to oil and gas companies in relation to funds held in a rehabilitation trust or company in accordance with section 37A of the ITA, as i) rehabilitation companies are not recognised as acceptable for financial provision and ii) rehabilitation trusts are only recognised to the extent of financial provision for latent or unforeseen liability post-abandonment.

To satisfy the immediate requirements of the NEMA regulations in terms of current financial provisioning, MPRDA rights holders may need to be replace the funding in a rehabilitation trust or rehabilitation company with one of the financial vehicles, namely financial guarantee issued by a financial institution, or a deposit with the Department of Mineral Resources. If funds are withdrawn from a rehabilitation trust or rehabilitation company, the market value of property so distributed is deemed to be taxable income which accrues to the trust or company during the year of assessment in which that distribution occurs, and is subject to corporate tax[105]. Furthermore, the Commissioner for SARS may impose a penalty equal to twice the market value of all the property held in the rehabilitation trust or company, and include that penalty in the income of the person who made the contribution to the rehabilitation trust or company[106]. These tax consequences make it prohibitive for oil and gas companies to satisfy the immediate NEMA financial provision requirements.

The Mining Report considers the difficulty of compliance with the NEMA regulations in part 3.4.1 (page 100) and recommends an amendment to section 24L to allow the tax deduction of contributions toward insurance products that fund financial provisioning for abandonment and rehabilitation.

*Proposed solution*

It is proposed by the DTC that Section 37A(7) of the ITA is amended by the following insertion:-

> “(7) If the company or trust contemplated in this section contravenes any provision of subsection (1)(*a*), during any year of assessment, by distributing property from that company or trust for a purpose other than –

[105] Section 37A(7) of the ITA

[106] Section 37A(8) of the ITA.

(b) rehabilitation upon premature closure;

(c) decommissioning and final closure;

(d) post closure coverage of any latent or residual environmental impacts; ~~or~~

(e) transfer to another company, trust, or account established for purpose contemplated in sub-section (1)(*a*);

(f) transfer to bank or financial institution against issuance of a guarantee for purpose contemplated in sub-section (1)(*a*); or

(g) transfer to account administered by the Minister responsible for mineral resources for the purpose contemplated in sub-section (1)(*a*),"

The proposed insertion of subsection (7)(*f*) and subsection (7)(*g*) will accommodate the tax-free transfer of funding held in a rehabilitation trust or rehabilitation company to the financial vehicles recognised in the NEMA regulations for the immediate financial provision required by MPRDA rights holders (including oil and gas companies).

## 10. International accepted practice

Petroleum activities around the world are subject to a great variety of taxation instruments. These include taxes that apply to all other sectors of the economy as well as taxes that are specific to the oil industry. In addition, non-tax forms of rent collection (such as surface fees, bonuses, and production sharing) are common[107] .

Special provisions, or incentives, are often included in petroleum fiscal regimes to modify the timing or magnitude of revenue appropriations. These provisions are normally intended as incentives designed to: (i) attract investors; (ii) accommodate unique attributes of a petroleum asset; or (iii) sway investors' choices toward specific public policy goals. Accelerated capital cost allowances, depletion allowances, interest deduction rules, loss carry-forwards, investment credits, and royalty or tax holidays are among the most commonly used special provisions[108] .

| | |
|---|---|
| Accelerated capital cost allowances | Assets are depreciated in many ways over their expected life (useful life of equipment, economic life of the reservoir). The methods used |

[107] Page 11 – Tordo, 2009

[108] Page 11 – Tordo, 2009

| | |
|---|---|
| | in the industry are: (a) straight-line (equal annual deductions); (b) declining balance (straight-line depreciation calculated for the remaining value of the asset each year); (c) double declining balance (doubles straight-line depreciation for the remaining value the asset each year); (d) sum of year digits (based on an inverted scale that is the ratio of the number of digits in a given year divided by the total of all years digits); and (e) unit of production (the capital cost of equipment, after deduction of the accumulated depreciation and of the salvage value, is multiplied by the ratio between the total production in a year and the recoverable reserves remaining at the beginning of the tax year). |
| Depletion allowances | The depletion allowance is the deduction from gross income allowed to investors in exhaustible commodities (such as minerals, oil, or gas) for the depletion of the deposits. The theory behind the allowance is that an incentive is necessary to stimulate investment in this high-risk industry: as the reservoir depletes, the company will need to undertake more exploration to find new reservoirs. The depletion allowance is meant to subsidize further exploration. Since the industry is a global one, it is quite likely that the depletion allowance may be used to subsidize exploration in competing countries. For this among other reasons, depletion allowances are granted/have been granted by only a few countries: Barbados, Canada, Pakistan and the USA. The Filipino Participation Incentive Allowance—FPIA - is similar to a depletion allowance. |
| Interest deduction rules | Project financing is quite common for large projects or for small oil companies. Normally interest on loans is deductible from taxable income and qualifies for cost recovery. Inter-company interest may also be cost recoverable and tax deductible, if calculated on an arms-length basis. |
| Loss carry forward | This refers to the ability of a company to “carry forward” losses from one year to offset tax liability in future years. When limitations apply the loss can be carried forward for a set number of years (normally 5 to 7) after which the benefit expires. In most cases, unlimited loss carry forward is granted. |
| Investment credits | In some countries, governments provide an incentive to investors by allowing them to recover an additional percentage of tangible capital expenditure (also known as investment uplifts or “allowances” and investment credits). In some cases investment credits can be taxable. |
| Tax holidays | When capital investment in a project is considerable, the host government may grant tax holidays to investors. For example, Myanmar offers a three year tax holiday period on income tax in its PSC. Tax holidays provide a valuable advantage to investing companies that can accelerate the project payback. On the other hand, host governments should be careful in utilizing this mechanism to attract investors. |
| Stability provisions | The stability of a fiscal regime impacts business confidence and affects the level of investment in, and pace of development of, existing projects. Stability clauses can be grouped under two categories: “freezing clauses” that maintain the contract and/or fiscal terms |

| | |
|---|---|
| | unchanged for the duration of the contract or for a certain period of time; and "equilibrium clauses" that allow for an adjustment of the contractual terms over time so that a change in circumstances does not damage or benefit one party to the advantage or detriment of the other. |

Table 3.1 The commonly used special provisions in the design of hydrocarbon fiscal regimes[109]

## 11. Alternative policy scenarios (Oil and Gas Phakisa project modelling)

In August 2013, President Jacob Zuma undertook a state visit to Malaysia. He was introduced to the Big Fast Results Methodology through which the Malaysian government achieved significant government and economic transformation within a very short time. Using this approach, they addressed national key priority areas such as poverty, crime and unemployment. With the support of the Malaysian government, the Big Fast Results approach was adapted to the South African context. To highlight the urgency of delivery the approach was renamed to Operation Phakisa - from a Sesotho word meaning "Hurry Up".

Operation Phakisa is a results-driven approach, involving setting clear plans and targets, on-going monitoring of progress and making these results public. The methodology entails eight sequential steps. It focusses on bringing key stakeholders from the public and private sectors, academia as well as civil society organizations together. Stakeholders collaborate in detailed problem analysis, priority setting and intervention planning. These collaboration sessions are called laboratories (labs). The results of the labs are detailed implementation plans with ambitious targets and public commitment on the implementation of the plans. The implementation of the plans is rigorously monitored and reported on. Implementation challenges are actively managed for effective and efficient resolution. Operation Phakisa is initially implemented in two sectors, the ocean economy and health[110].

Contained within the ambit of the focus of ocean economy is a focus on the promotion of the exploration and production of offshore oil and gas. An identified obstacle in the stimulation of the offshore oil and gas industry was the uncertainty created by the 2014 Amendment Bill for the MPRDA.

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[109] Adapted from Tordo, 2007:12-14
[110] Operation Phakisa.gov.za, 2014

The 2014 MPRDA Amendment Bill provides for a 20% free carried interest, without clearly defined parameters. The possible interpretations of the State's "fee carried interest without financial obligation" are:

- The oil and gas rights holder will lend to (carry) the State to finance the State's 20% participation in the Development capital expenditure, and no interest will be paid by the State on the loan extended by the oil and gas rights holder. The loan is repaid by the State from its share of production;
- The oil and gas Rights holder will lend to (carry) the State to finance the State's 20% participation in the Development capital expenditure, and the State will pay interest on the loan extended by the Oil and Gas Rights holder. The loan is repaid by the State from its share of production;
- The oil and gas Rights holder pays (incurs) the State's 20% participation in the Development Capital expenditure with no recovery of the expense from the State. The State pays for its 20% participation in relation to operating expenses from development;
- The Oil and Gas Rights holder pays (incurs) the State's 20% participation in the Development Capital expenditure and operating expenses with no recovery of these expenses from the State.

The Ocean Economy Lab modelled the various possible interpretations of this free carried interest, the results of which are presented in Annexure J.

# 12. Analysis of key tax issues including those raised by stakeholders.

## 12.1 The significant discovery

The US Department of Energy, in 2011, reported technical recoverable shale gas resources for South Africa of 485 Tcf, making it the 5th largest country in the world with respect to shale gas resources. There is, however, as yet no firm knowledge of the size of the resource, and estimates given by different bodies, none of whom have performed on-site exploration, vary widely from 15 to 75 Tcf of recoverable resources. To put this in perspective, the offshore gas field which has supplied the Mossgas refinery for 20 years has a capacity of just under 1 Tcf and is about to run out. 1 Tcf would also fire a 100mw base load power station for 20 years.[111]

South Africa is not yet a significant producer of crude oil or natural gas, as such the fiscal terms (tax rules) are designed to attract investors to engage in exploration activities. In the situation of a significant discovery made in South Africa, the geological uncertainty will have reduced, paving the way for stricter fiscal terms. In a number of countries, very significant changes to fiscal terms have been introduced as 'prospectivity' has improved. If properly managed and timed, it seems that a review of fiscal terms need not affect a country's reputation for fiscal stability or discourage investment.

The prospect of significant shale gas reserves could reasonably act as a timing trigger for a review of South Africa's terms, both with an eye to shale gas extraction itself, but also in relation to creating a more flexible fiscal regime which would automatically adapt to changing prospectivity elsewhere (for example, in offshore exploration).

The DMR has asked for proposals on a mechanism whereby state participation can be increased in the scenario of a significant discovery.

State participation internationally takes various forms:

1. *Fixed Share*: Examples of a fixed-share are reflected in the PSCs written in Indonesia.
2. *Production Rate*: The state participation would be written around cumulative production, with changes in total oil or gas produced driving the change in allocation (for example Nigeria Deepwater, Malaysian offshore and Egypt). In some cases they may, however, be based on the absolute volume of daily production planned (for example Qatar).
3. *R-Factor*: This is a negotiated figure set on the basis of the indicated ratios of cumulative revenues over the cumulative investment costs incurred. Examples of countries that tend towards R-factor based contracts include Yemen, Qatar and Libya.

[111] Department of Mineral Resources (Republic of South Africa), 2012. Report on investigation of hydraulic fracturing in the Karoo basin of South Africa. Available at: < http://www.dmr.gov.za/publications/summary/182-report-on-hydraulic-fracturing/853-full-report-on-investigation-of-hydraulic-fracturing-in-the-karoo-basin-of-south-africa-.html > .

4. *Internal rate of return ("IRR"):* This scheme is very flexible to variations in profitability from all sources, namely (a) oil/gas price movements, (b) variations in field sizes, and (c) variations in investment costs. IRR based state participation is structured such that, depending upon the internal rate of return that the project has achieved, the State's share of profit oil barrels will alter. IRR arrangements will typically allocate a higher share of revenues to the contractor through the early phases of a project, but a greater share to the state as the contractors' capital is recouped and the rate of return on the project rises. Indeed, as the name suggests, changes in the allocation of barrels between state and contractor (trigger points) tend to be associated with the achievement of different internal rates of return. Countries which commonly use IRR-based contracts as a mechanism for determining share include Angola, Russia, Kazakhstan, and Azerbaijan, amongst others.

The Department of Mineral Resources made a specific request to look at the concept of Additional Oil Entitlement (AOE) as applied in Ghana. The AOE is computed based on the after royalty, after-tax inflation adjusted Rate of Return which the upstream exploration company has achieved with respect to a development and production area. Accordingly, the upstream exploration company must first recover its capital and operating expenditure and achieve an after-tax inflation adjusted level of profitability before AOE becomes payable.

| **Real rate of return** | **Real rate of return threshold % + i** | **AOE Rate%** |
|---|---|---|
| 25% or less | 0.00 | 0.00 |
| Over 25% | 27.50% | 7.50% |
| Over 30% | 32.50% | 15.00% |
| Over 40% | 42.50% | 25.00% |

| | | |
|---|---|---|
| i = USIGWPI | 2.50% | Default value |

Two alternative options are recommended for increasing South Africa's state participation in the event of a significant discovery:

Option 1 – *Cumulative rate of production*. When cumulative production reaches a specified quantum it acts as the trigger for increases in state participation. The rationale favouring this option is that:

- It overcomes the State being locked into a fixed share/percentage upfront in an environment of geological uncertainty. The fixed percentage may be generous in the context of a significant discovery or may be perceived as too high and discourage investment when South Africa's geological resources are still unknown;
- It is simplistic in its determination of the allocation to the State, and production will not be suppressed to avoid taxation when cumulative production values are utilised. As the achieved cumulative production reaches each target an increase in the percentage of State participation is suffered but, correspondingly, the upstream exploration company is realising production volumes and profits greater than those of preceding commercial discoveries made in South Africa.
- R-factor, internal rate of return and AOE are difficult to calculate, onerous to administer in terms of retention of historical values and subject to manipulation. For example investment costs which need to be recovered before increases in the State participation may be overstated through inter-company charges such as services rendered by foreign holding company.

Option 2 – *Fair share allocation* .The problem with option 1 is that it ignores profitability which depends on factors such as the oil price, capital and operating costs. Option 2 is to give the State rights to increase its participation once certain generous recovery of capital and costs have been met. In a frontier area such as South Africa the tax system must be generous to attract investment. Without a generous tax system there will be no investment. It is inappropriate to label South Africa as overly generous without comparing the profitability of South African oil and gas production with countries that have similar geological uncertainty and no proven significant commercial discoveries. Namely South Africa should not be compared with other countries on an AETR basis, but on the basis of the Economic Monetary Value (EMV) to the investor.

Irrespective of the option chosen, the Davis Tax Committee cautions that increases in State participation are accompanied by an increase in the burden of abandonment at the end of life of a project. Accordingly, if any mechanism for increases in State participation is to be implemented these should be in conjunction with a mechanism that provides for financial provisions to be set aside prior to end of life. The international comparable mechanism, recommended in this regard, is an obligatory provision for abandonment (as a percentage of production) paid toward Government for remediation of the gas/oil well from when 50% of recoverable reserves are reached.

## 12.2 IMF report on fiscal regimes for mining and petroleum in South Africa

The IMF Fiscal Affairs Department was commissioned by the Davis Tax Committee to prepare a report on the South African mining regime. In 2015, the IMF issued report, *Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges* identifying specific concerns in relation to Petroleum Taxation and makes Recommendations for amendment to Petroleum Taxation in South Africa. What follows is review of the IMF report to confirm or furnish explanations:

### 12.2.1 Specific rules apply to petroleum extraction

The IMF[112] raises the concern that "mining" provisions under the ITA may be applied to oil and gas companies, allowing for possible abuse where the ring-fence for a particular expense is broader or narrower under the mining provision than under a Tenth Schedule provision. The ring-fencing under the Tenth Schedule differs from the general mining provisions under the ITA, in that the only ring fence under the Tenth Schedule is found at paragraph 5(3) which limits the offset of oil and gas tax assessed losses against non-oil and gas income to 10%.

Furthermore, the IMF indicates that there might be reconciliation issues between the general provisions of the ITA and the provisions of the Tenth Schedule. The Tenth Schedule, as indicated at section 26B of the ITA, overrides the general provisions of the ITA. Where a matter is not specifically dealt with within the ambit of the Tenth Schedule, however, that matter remains to be dealt with in accordance with the general provisions of the ITA, such as anti-avoidance and transfer pricing.

Finally the tax rates for petroleum are set out in the Tenth Schedule, and not in the tax rates as gazetted in accordance with section 5 of the ITA. The rates for petroleum are expressly stipulated in the Tenth Schedule to accommodate preservation of the rate in the

[112] Page 12 - Daniel, P., Grote, M., Harris, P. & Shah, A. (2015). Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges. Report prepared for Davis Tax Committee. Pretoria: International Monetary Fund.

circumstance that a fiscal stability agreement is entered into between the Minister of Finance and the oil and gas company, as provided for at paragraph 8 of the Tenth Schedule.

### 12.2.2 Reconnaissance

The IMF[113] raises the concern that reconnaissance operations are not dealt with in the general provisions of the ITA. In the context of oil and gas companies, the Tenth Schedule to the ITA (at paragraph 1) includes, by definition, reconnaissance operations carried out under the ambit of a reconnaissance permit. As observed by the IMF, the gain realised on the disposal of a reconnaissance permit is oil and gas income for purposes of the Tenth Schedule, and paragraph 7 elections on the disposal of such an oil and gas right may apply.

Furthermore, in the context of oil and gas companies, the person holding a reconnaissance permit is deemed to be carrying on a trade, and the expenditure is deemed to be incurred in the production of income[114]. Expenditure incurred in reconnaissance will be deductible under paragraph 5 of the Tenth Schedule in accordance with the treatment of such expense as either revenue or capital in nature.

### 12.2.3 Exploration vs post exploration expenditure

Section 36(11) of the ITA provides a definition of 'capital expenditure' for hard rock mining purposes. What is, and what is not, 'of a Capital nature' is not defined in the ITA for Tenth Schedule purposes and depends on a complex body of case law. The established legal precedence should be followed to classify expenditure incurred as 'capital' or 'revenue' in nature correctly.

The accounting classification of plant, property and equipment (PPE) includes the capitalisation of:

- direct costs incurred in procuring the asset;
- costs incurred to fulfil performance condition – location (transportation costs);
- costs incurred for intended purposes – ready for intended use (installation costs); and
- costs incurred for intended purpose – meet operating requirements (testing costs).

[113] Page 13 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[114] Page 14 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

The accounting treatment of exploration costs is to capitalise all costs from the date of obtaining the oil and gas right to 'intangible assets'. Should a commercial discovery be made, the capitalised exploration costs are moved from intangible assets into PPE, and further field development costs are then capitalised directly to PPE. If the exploration and appraisal proves unsuccessful (for example dry hole), the exploration costs are expensed through profit and loss. The tax treatment does not follow the accounting treatment, as a deduction for capital expenditure is allowed under paragraph 5 of the Tenth Schedule irrespective of the success or failure of the exploration activities. It is recommended that the SARS issue an Interpretation Note to provide further clarity on the classification of "capital expenditure" for purposes of the Tenth Schedule.

The Tenth Schedule allows for a 100 percent uplift in the deduction of 'exploration' capital expenditure, and a 50 percent uplift in the deduction of 'post-exploration' capital expenditure. The IMF[115] indicates that the absence of a reference to whether an activity is conducted under an exploration or production right is likely to create difficulty in determining whether particular expenditure qualifies for the 100 percent or the 50 percent uplift. The distinction between 'exploration' and 'post-exploration' is defined in the Tenth Schedule and reference is made to the activity carried out to determine its treatment as 'exploration' or 'post-exploration' because exploration activities can be carried out by an MRPDA production right holder. Correspondingly, field development activities which are recognised as 'post-exploration' may be undertaken by an MPRDA exploration right holder but such right holder will need to obtain an MPRDA production right prior to producing from a completed oil or gas well.

The difference in the tax treatment between 'exploration' and 'post-exploration' expenditure may have distorting effects, according to the IMF[116], where it may be desirable from a tax perspective to hold an exploration right for as long as possible to support an argument that capital expenditure must be exploration expenditure. The current recognition of expenditure as 'exploration' and 'post-exploration' for purposes of the uplift on capital expenditure is tied to the activity undertaken as opposed to the type of MPRDA right held by the oil and gas company, to prevent manipulation of the capital uplift deduction based on the type of right held.

[115] Page 15 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

Oil and Gas companies are specifically excluded from obtaining the 150 percent deduction for research and development expenditure at proviso (e) to section 11D(1) of the ITA.

The IMF[117] recommends a unified treatment of exploration and post-exploration expenditure, with write offs over five years commencing when the asset is placed into service. Whilst a five year write off period is aligned with international standards for oil and gas countries, it should be acknowledged that such countries that have adopted the five year write-off already have significant commercial discoveries of oil and gas. The IMF[118], in its economic model, recognises that its own analysis of exploration risk, at current and prospective oil prices, shows the estimated exploration “plays” to be marginal within the existing fiscal regime. The aim of the generous fiscal terms, such as the immediate write off and capital uplifts for capital expenditure, are to attract investors and encourage exploration.

A subsequent report[119] from the IMF, which models these aspects, indicates a marginal difference between the immediate deduction with the uplifts, and an Allowance for Corporate Capital (ACC) at 10% uplift with a deduction of capital expenditure over five years.

### 12.2.4 Recoupment of capital expenditure

The IMF[120] observes that there is no recoupment if capital expenditure is redeemed on the disposal of an asset that qualified for the deduction. This is not unique to the Tenth Schedule and is observed in the First Schedule, farming tax legislation.

The disposal of an oil and gas right (asset) is expressly dealt with in accordance with paragraph 7 of the Tenth Schedule, which allows for the election of the participation or rollover election or the default to treat the capital gain or loss on disposal in accordance with in the Eighth Schedule. The tax assessed loss generated through the uplift on capital expenditure remains with the taxpayer disposing of the oil and gas right. This is consistent

[117] Page 44 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[118] Page 52 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

[119] June 2016 Report from IMF.
[120] Page 17 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

with the tax treatment of the disposal of section 36(11) mining assets in hard-rock mining, where there is no recoupment of the unredeemed capital allowance (granted at 12% per annum under section 36(11)(c) of the ITA).

Under the 'rollover election', the IMF[121] highlights that the seller may realise no taxable gain, even in the scenario that the petroleum right is sold for a large gain, such as in the case of a substantial discovery. The untaxed capital gain is passed on to the buyer in such an election, in that the base cost of the oil and gas right acquired is limited to that of the seller and not to the consideration paid for the asset.[122] Thus, if there were continual use of the rollover election, in the context of successive farm-in and farm-outs[123] the capital gain realised on disposal might never suffer taxation and may be deferred indefinitely.

Furthermore, as pointed by the IMF[124], if this were the seller's only asset, and the seller ceased to trade for a period of 12 months, the tax assessed loss of the seller would be lost for section 20 purposes. However, where the seller continues to hold other petroleum rights, or continues to trade, the tax assessed loss may be carried forward for offset against its other oil and gas activities, and to provide 10% of oil and gas losses against income from non-oil and gas activities.

Under the participation election, the IMF[125] states that if a large discovery is made and the proceeds of the sale exceed carry forward losses, this option will produce income that is taxable in full for the seller. The buyer correspondingly receives an immediate deduction under paragraph 5 (but without the additional capital uplifts). So, effectively capital gains treatment is excluded for both the seller and the buyer. This treatment, under the participation election is similar to the tax treatment of the disposal of mining assets under section 37 of the ITA for mining companies. Section 37 of the ITA recognises the proceeds on the disposal of a mining asset as a recoupment of capital allowances (namely gross income) and allows the buyer to claim a deduction of the proceeds as capital allowances under

[121] Page 25 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[122] The untaxed capital gain if the buyer were to onward sell the petroleum right without a rollover election reduces in value as the resources are extracted.
[123] The term farm-in farm-out refers to agreements in the oil and gas industry, in terms of which a third party acquires from one or more existing licensees/ lessees ('owners') an interest in a production license/ lease and/or the associated operating agreement, in return for specified services.
[124] Page 25 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[125] Page 25 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

section 36(11) of the ITA. The participation election remains an election of the seller, and not the default position for the treatment of the disposal of an oil and gas right. It is envisaged that this election would only be made by a seller where it is the intention of the contracting parties to realise portion of tax assessed loss of the seller and, in effect, allocate same to the buyer.

The IMF[126] proposes revision of the tax treatment of acquisition costs of a petroleum right in terms of allowing for amortization of acquisition costs and, furthermore, proposes revision of the rollover and participation elections ("arrangements"), with appropriate safeguards.

### 12.2.5 Rehabilitation

The IMF[127] considers the possibility that rehabilitation expenditure might qualify for uplift on capital expenditure where claimed as a deduction under paragraph 5(1) of the Tenth Schedule, as opposed to section 37A of the ITA. The definition of post-exploration expenditure is wide enough to incorporate rehabilitation expenditure. Section 23B of the ITA states that where a taxpayer qualifies for deduction or allowance under more than one provision of the Act, a double deduction is not allowed. But under the common law principle, *lex specialis derogat legi generali* only the deduction or allowance specific to the nature of the expenditure suffered should be allowed, namely section 37A with respect to rehabilitation expenditure.

### 12.2.6 Assessed losses

The IMF[128] observes that assessed losses from non-petroleum activities may be offset against oil and gas taxable income. Paragraph 5(4) allows the offset of 10% of oil and gas tax assessed losses against taxable income from non-petroleum activities. The definition of 'oil and gas company' is, however, restricted to a company that holds a South African MPRDA right. There are no limitations on such company with respect to carrying on other trades simultaneous to its oil and gas activities.

Due to the high risk nature of exploration, oil and gas companies are unable to secure external funding for such activities. Accordingly, oil and gas companies need to self-fund such activities from their investment holdings (namely off-balance sheet). An oil and gas

[126] Page 55 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[127] Page 18 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

[128] Page 23 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

company engaged in exploration and appraisal may have substantial investment holdings. The primary purpose of allowing the offset of 10% of oil and gas tax assessed losses against taxable income from non-petroleum activities was to accommodate tax offsets for interest and taxable profits derived from such investments holdings.

The Oil and Gas stream of Project Phakisa is focused on what support industries are necessary to encourage offshore exploration and production in South Africa. An oil and gas company may diversify its trade, particularly where limited local suppliers exist in the service of the oil and gas industry. Oil and gas companies have had to make investments in support services such as warehousing, laydown areas, support vessels and emergency vessels etc where such services are not available locally, and may lease these support services to each other. As observed by the IMF[129] , 10% of the excess losses may be offset against such non-oil and gas activities. These oil and gas companies would benefit from the ability to offset a small portion of their oil and gas tax assessed losses against their taxable income derived from investments into support industries. The 10% is available each year for the duration of the tax assessed loss from oil and gas activities.

The IMF[130] furthermore states that refining is not a "post-exploration" activity, yet paragraph 5(3) recognises that refining can fall within the scope of an "oil and gas right". This specific inclusion of refining, at paragraph 5(3), is to accommodate the offset of tax losses generated by the uplift of capital expenditure, incurred in the exploration and production of oil and gas, against taxable income from refining. The aim of this specific inclusion is to encourage local beneficiation of South Africa's oil and gas petroleum resources through the refining of indigenous condensate and gas. Imported condensate (and crudes), imported LNG feedstock and imported blend-stocks (used to achieve the liquid fuels specifications in terms of octane requirements) to the refinery will not qualify for the offset of tax losses from exploration and production expenditure in relation to an MPRDA right.

### 12.2.7 Fiscal stability agreements

Paragraph 9 of the Tenth Schedule of the ITA provides for the conclusion of fiscal stability agreements with petroleum rights holders. The Minister of Finance may enter into an

[129] Page 23 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[130] Page 23 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

agreement with the right holder guaranteeing that the provisions of the Tenth Schedule at the date of the agreement will continue to apply for as long as the company holds the right. This limited right of fiscal stability means that any alteration to the general ITA provisions applicable to petroleum can affect the rights holder despite an agreement [131].

The conclusion of a fiscal stability agreement will freeze the Tenth Schedule of the ITA for both the benefit and to the detriment of a right holder. To secure the benefit of a change in the Tenth Schedule, the rights holder would have to unilaterally terminate the agreement under paragraph 9(4), in which case the safe harbour would, from then on, no longer be available[132]. The fiscal stability under the OP26 regime, was asymmetric: protecting the investor from adverse changes to the fiscal terms but passing on benefits of economy-wide reductions in tax rates or tax deductions that are more favourable, as between the Income Tax Act as at 1977 and the current Income Tax Act.

To date, ten petroleum fiscal stability agreements have been concluded.

The fiscal stability provision for the royalties has been less popular. Section 13 of the Mineral and Petroleum Resources Royalty Act (MPRRA) provides the Minister of Finance with the power to conclude a royalty fiscal stability agreement. The agreement is limited to only assurance with respect to no changes to the royalty formula. So, for example, a royalty agreement would not have protected a rights holder from the changes to the valuation rules in 2013. According to the IMF[133] this may be the reason why such agreements have not been popular. To take advantage of a change in the formula that benefits the rights holder, the rights holder would have to unilaterally terminate the royalty fiscal stability agreement[134].

The IMF[135] recommends a review of the approach to the assurances of fiscal stability. As indicated above, the application of the fiscal stability agreements are limited in scope and do not prevent the introduction of changes to the body of the ITA or the MPRRA (with the exception of the royalty formula), or the introduction of new tax legislation. However, fiscal

[131] Page 28 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[132] Page 29 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

[133] Page 29 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[134] Section 13(5) of the MPPRA
[135] Page 29 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

stability is essential to secure investor confidence in the oil and gas environment where the capital outlay is significant and the geological uncertainty is pervasive.

It is recommended that, in the event of a significant discovery, Government allows fiscal stability for the 'first-mover' companies, and deals with the transition to any new tax dispensation by enforcing the relinquishment provisions under the MPRDA which compel the size of a block/field to shrink as the oil and gas project moves thorough the life stages (for example, the conversion of an exploration right into a production right). Any new tax dispensation will then apply prospectively to all new rights issued, including the acreage that is released through the relinquishment process. This provides predictability to the "frontier" investor, confronted by huge geological and commercial risk which is difficult to quantify *ex-ante*, but still allows policy flexibility to Government once the extent of commercially viable resources can be more accurately scoped.

### 12.2.8 Royalty rate

The IMF[136] recommends that the variable rate royalty is converted into a flat rate royalty, with rates up to 5% on gross sales at the point of actual sale or first saleable point. It is agreed that the royalty rate formula is subject to interpretational differences in relation to the accounting concept of EBITDA and the tax adaption of the concept to reflect taxable income. A flat royalty would make the determination of the royalty simple and easier for both revenue authority and taxpayer to administer, in the context of petroleum resources. The Mining Report recommends, in the context of hard-rock mining, to broadly maintain the formula based royalty, with clarification of the determination of the gross sales tax base. The Mining Report makes this recommendation because the royalty formula is designed to marginally increase the rate of taxation depending on the profitability of the mine. In other words, within a certain profitability range the rate formula is designed to capture rents. This capture of rent provides relative tax neutrality as revenue varies based on project profitability.

In contrast to the Mining Report which is concerned about the royalty cost burden to a marginal mine that may result in such a mine's premature closure, the IMF's economic

[136] Page 44 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

assessment of South Africa's petroleum fiscal system simulation reflects that, when an oil and gas company enters production, the oil and gas company almost immediately begins to pay royalties at the capped maximum rate and continues at this royalty rate for the significant portion of the life of the field. The likely reason is that when economic field size thresholds are applied by oil and gas companies', uneconomic fields are not developed and such fields accordingly never enter production.

It is interesting to note that both the first and second draft Mineral and Petroleum Resources Royalty Bills [B1,2006] provided, initially, for fixed rate royalties to be applied to the different types of minerals and, in the case of petroleum resources, a royalty rate of 1.5% for onshore or shallow-water and a royalty rate of 3% for deep-water. These royalty rates were met favourably by the industry.

The basic criterion of a good corporate tax system is that it taxes profits and not revenues. A low royalty rate does not significantly impact investment decisions. A high rate has an adverse impact on the decision to investment because it substantially increases project risk.

### 12.2.9 State Participation

The IMF [137] acknowledged the uncertainty that has been introduced in the MPRDA Amendment Bill in reference to State participation. The combination of this situation with the sharp fall in oil prices over the last half of 2014 has already caused a hold up in exploration programs.

The lack of clarity on State participation means that companies are unable to calculate the full effect of the fiscal regime on their anticipated returns from a successful discovery. The exploration expenditure is thus less likely to be undertaken.

The IMF[138] recommends three options to deal with the uncertainty of State participation:

- *<u>Option One: Delete the state participation provisions altogether in revision of the MPRDA Amendment Bill</u>*..

[137] Page 56 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015
[138] Page 58 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

- *Option Two: Comprehensive shift to a production sharing contract (PSC).* It took 4 years from the inception of the MPRDA (2002) to the gazetting of the Tenth Schedule (Nov 2006). A comprehensive shift from the concession legal arrangement to a contractual legal arrangement is likely to take as long. In this interim period a vacuum of fiscal uncertainty would exist, deterring both existing and potential new oil and gas investors from entering into new MPRDA rights and executing work-programs;
- *Option Three: Define the state participation option precisely and publish a model participation agreement that the companies with exploration rights could sign.* The definition would apply to the terms of the maximum 20 percent carried participation. It could include the participation terms common elsewhere – a carry for the state participant through exploration with a paid interest at the development stage, albeit one which the private parties could finance, and be rewarded with a commercial interest rate plus a premium. Option Three is favoured by the Davis Tax Committee (see 13. Findings and Recommendations).

The IMF[139] favours option one, or option one in combination with option three if non-fiscal considerations favour State participation. Regarding option two, production sharing, the IMF advises that it will make it easier to offer comprehensive fiscal stability in the contract, and higher state shares might be the reward for that.

## 12.3 Alternatives to State Participation

The objective of State Participation needs to be clear. There are considerations for Public Financial Management, such as who will collect the petroleum revenues and who will benefit from the petroleum revenues. If the aim of State participation is revenue generation for the state, this may be achieved by the introduction of a tax instrument together with enhancement of the technical capability of the regulator, and improvement in the regulations. The use of a tax instrument allows for petroleum revenues to be collected for the benefit of the National Revenue Fund, and the administration of the revenue collection to be performed by the SARS.

[139] Page 58 - Daniel, P., Grote, M., Harris, P. & Shah, A. ,2015

The Davis Tax Committee examined the possibility of an increase in the royalty rate as an alternative to State participation. But a change in the royalty regime must not be considered in isolation. The royalty regime is part of the broader tax mix for oil and gas companies. In this regard, if Government were to legislate for a higher royalty rate and lower corporate income tax (CIT) rate, this would help to curtail transfer pricing (BEPS), investors would have more certainty in computing the average effective tax rate (AETR) and would be able to factor in a royalty as a cost of doing business with relative ease. The downside of a royalty is that it is a financial charge related to revenue on revenue and not profits. Accordingly, if Government's desired outcome is investment in the oil and gas sector, and consequent economic growth, royalties should continue to be imposed at a relatively low rate (5%).

The IMF has recommended, as an alternative to State Participation, the use of a Cash Flow Surcharge. The Cash Flow Surcharge of 20% becomes payable on taxable income, net of royalties, when the oil and gas company has redeemed the full amount of its capital expenditure, with a once off 10% uplift. The IMF simulation model results, from the Cashflow Surcharge, produce a South African AETR of 55.9%[140]. This is significantly higher than the current regime results of AETR at 47,7%. However, it is marginally more palatable to the oil and gas company than the simulation results of State participation at 20%, namely AETR at 58,9%.

State participation in petroleum rights may be fundamental to ensuring that the petroleum sector matures in a manner that it favours South Africa's developmental State agenda. For example the DMR may favour the use of the Norwegian model for State participation, namely State participation is exercised and administered through the National Oil Company (NOC). Such active technical and commercial participation, by the NOC in an oil and gas right, cannot, however, be achieved by regulatory oversight and taxation alone[141].

[140] Page 12, Simulation Results – Scenario 4, IMF 2016.
[141] Marcel, V. (2013). Guidelines for good governance in emerging oil and gas producers. London. Chatham House.

## 12.4 The Wait et al Economic Study

The Wait et al Study[142] links petroleum fiscal regime instruments (such as the royalty, CIT and resource rent tax) to impacts on economic growth, investment and employment in South Africa, using Computable General Equilibrium (CGE) modelling. The most important finding of the Wait Study is that it provides some evidence that, in increasing Government's take, there is a trade-off between stimulating investment and exploration (i.e. favoured by the current petroleum regime) and stimulating GDP growth. Wait et al, in their modelling simulation, found that "Output from these upstream industries declined in both the short and long run due to the expansion of production from the crude oil, petroleum and gas sector, alongside different forms of increased taxation". As a result, some upstream industries show lower demand for inputs, including labour (p 13). The Wait study finds that, while industries producing capital equipment for oil and gas do expand employment, agriculture on the other hand, potentially, suffers the greatest contraction in employment. Furthermore, in the short run, an increase in oil and gas output increases employment, but it encourages a long term shift to skilled, rather than unskilled, labour.

The Wait Study recommends that the current taxation system remain in-tact. With reference to the analysis in the Wait paper, there are strong arguments in favour of preserving the *status quo* as it will help to clear the way for South Africa to attract the necessary upstream investment to accelerate the development of the crude oil, petroleum and gas sector, and ensure its sustainability well into the future.

[142] Wait, R., Rossouw, R., Loots, E. and Bezuidenhout, H. (2015) The effects of licensing and tax policy on the development of the upstream oil and gas sector: the case of South Africa. Potchefstroom, School of Economics, North-West University.

# 13. Findings and recommendations

13.1 South Africa currently has a well-established and efficient tax system, on the whole, so major changes are not necessary. The Tenth Schedule (subject to minor refinements, as proposed) is appropriate to attracting oil and gas investors in an environment of geological uncertainty.

13.2 This report recommends minor enhancements to the Tenth Schedule and ITA with respect to:

- transferability of fiscal stability;
- preservation of fiscal stability;
- extension of the definition of oil and gas company; and
- rehabilitation trusts and companies.

13.3 This report recommends amendment to the Eighth Schedule, to accommodate the taxation of the disposal of shares in an oil and gas company by a non-resident.

13.4 In the event of a significant commercial discovery, the Tenth Schedule fiscal stability is limited to safeguarding only the provisions of the Tenth Schedule, and does not restrict the legislator from introducing new legislation outside of the Tenth Schedule (such as within the MPRDA), or within the body of the ITA. It is recommended that government allow fiscal stability for the 'first-mover' companies, and deals with the transition to any new tax dispensation by enforcing the relinquishment provisions under the MPRDA which compels the size of a block/field to shrink as the oil and gas project moves through its life stages (for example, the conversion of an exploration right into a production right). Any new tax dispensation will then apply, prospectively, to all new rights issued, including the acreage that is released through the relinquishment process. This does not necessarily mean that, following a significant oil or gas discovery, taxation will increase. However it does provide the opportunity to review the tax system in light of new circumstances.

13.5 State Participation, as formulated under the MPRDA Amendment Bill forms part of Government Take and should be taken into consideration in the analysis of the total tax burden of an oil and gas company. Instruments of State Participation have a fiscal effect on the division of revenues even when held by a commercially operating state owned enterprise, and should be regarded as part of the broad fiscal regime in addition to more conventional instruments such as royalties and income taxes.

13.6 To ensure investor confidence, the mechanics for State participation should be clarified in the MPRDA and clearly articulated in the Exploration and Production Right, issued by the Department of Mineral Resources.

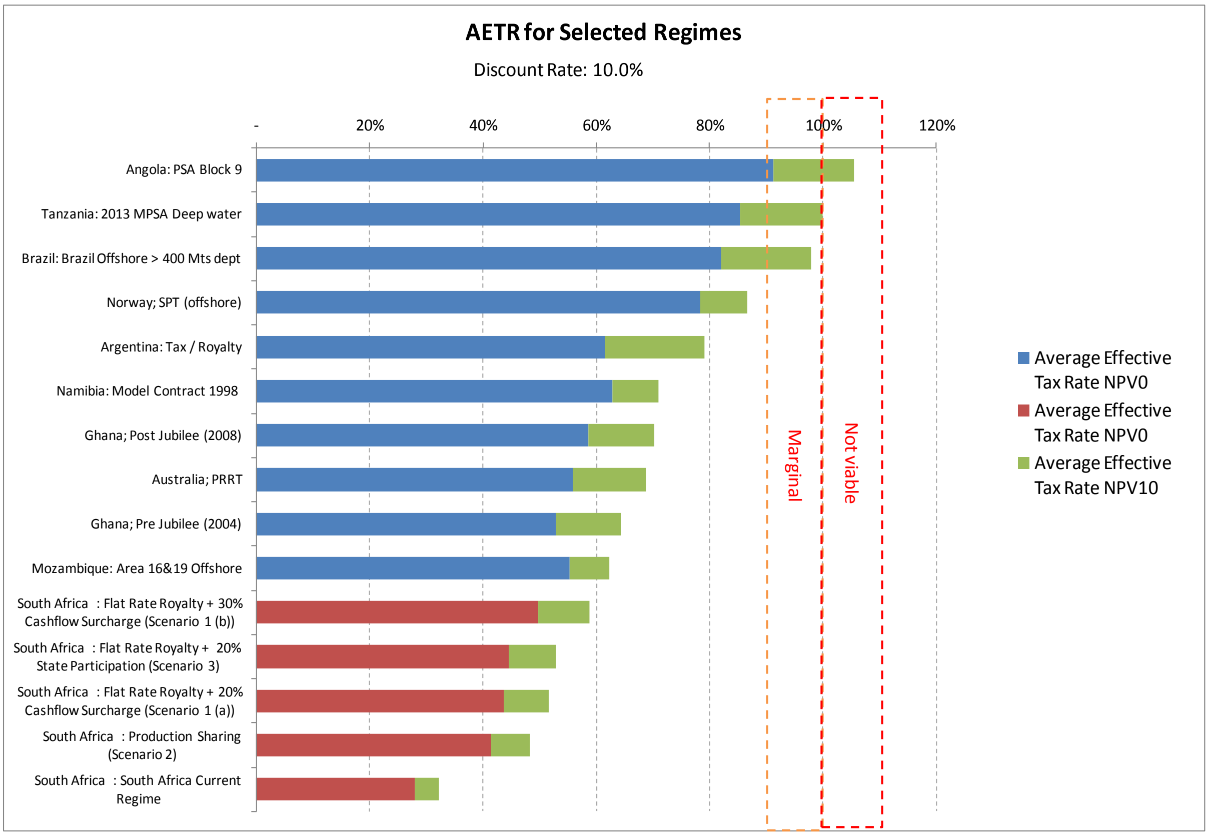
13.7 A fixed rate royalty for oil and gas, to replace the current variable royalty rate formula, would simplify the administration of royalties and, accordingly, the recommendation of the IMF (2015:44) for a 5% flat rate royalty is supported in the context of petroleum resources. In the context of hard-rock mining, the Mining Report recommends to broadly maintain the formulae based Royalty, with clarification of the determination of the gross sales tax base.

13.8 The IMF recommended for a depletion allowance in relation to the acquisition of MPRDA rights. In the context of oil and gas there is a deduction in relation to the consideration paid for an oil and gas right in the form of the participation election at paragraph 8 of the Tenth Schedule. Thus, the DTC does not consider that any change is necessary.

13.9 As informed by the Wait Study, even if attracting investment in the oil and gas mining sector does not yield significant tax revenue for the *fiscus* (and contribute substantially toward GDP as a percentage), the multiplier effect of such an investment provides the platform for job creation. The primary advocacy for encouraging exploration and exploitation of South Africa's oil and gas potential is contained in the National Development Plan, which comments that gas (indigenous or imported LNG) could make a significant contribution to South Africa's energy needs, whilst reducing greenhouse gas emissions and carbon intensity. In conclusion, as indicated above, in an environment of substantial geological and policy uncertainty, the DTC recommends retention of the existing attractive fiscal regime for oil and gas companies.

## ANNEXURE A

Average Effective Tax Rate (Government Take) for Selected Regimes (IMF, 2015:53)

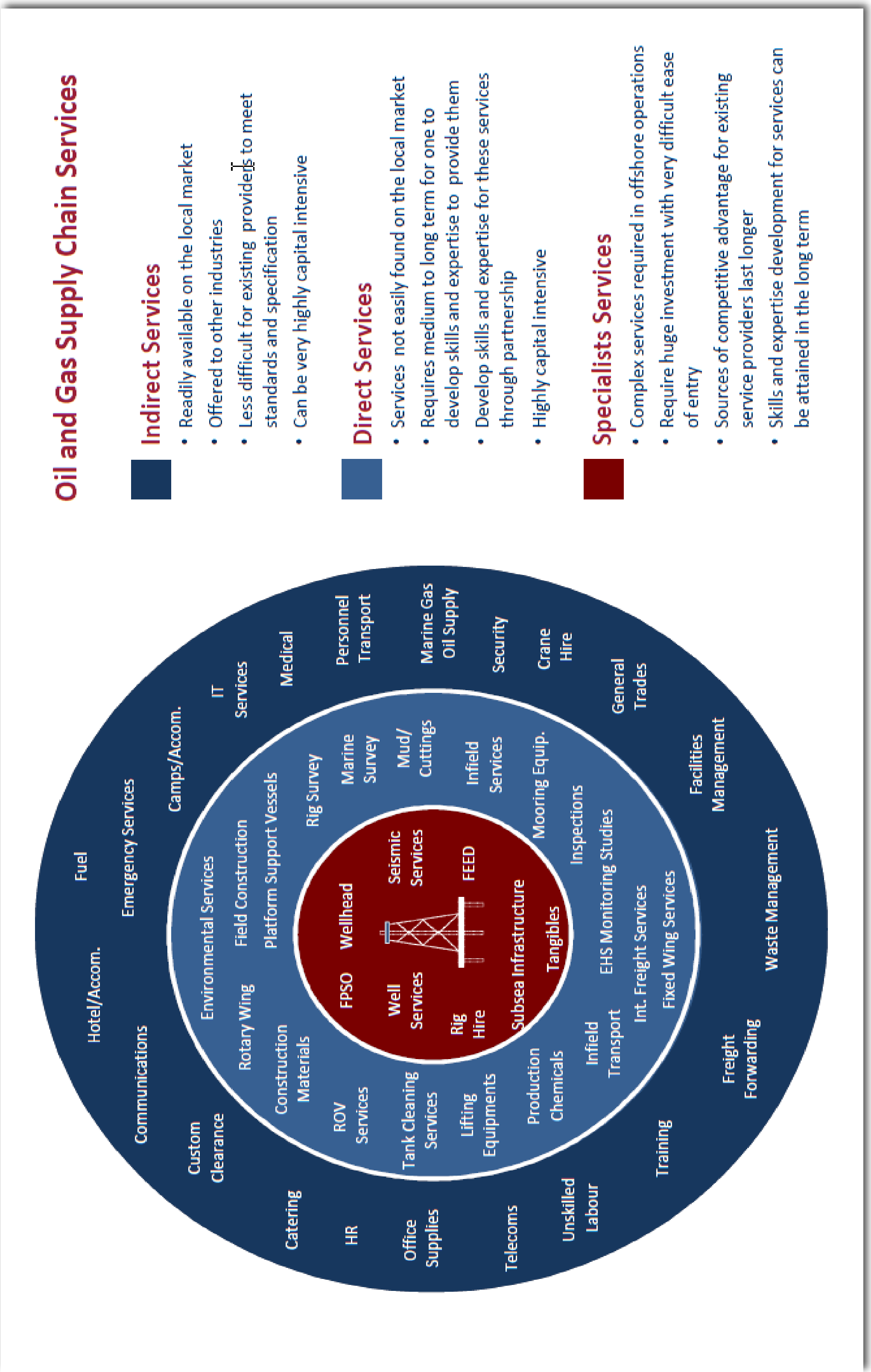



In the IMF's economic modelling of South Africa's fiscal terms, South Africa compares favourably against other African and international countries on an AETR %. Unfortunately, this comparison does not take into account the geological uncertainty and level of maturity of oil and gas in South Africa. More relevant comparison of fiscal terms is made by evaluation of EMV to the investor.

In a purely competitive world, countries with favourable geologic potential, high wellhead prices, low development costs, and low political risk will tend to offer tougher fiscal terms than those with less favourable geology, low wellhead prices, high development cost, and high political risk. The economic strength and political stability of the country, oil supply balance, regional market demands, global economic conditions, and financial health of the petroleum sector also influence fiscal terms. It is commonly accepted that the level of government take is inversely proportional to the quality and availability of investment opportunities[143].

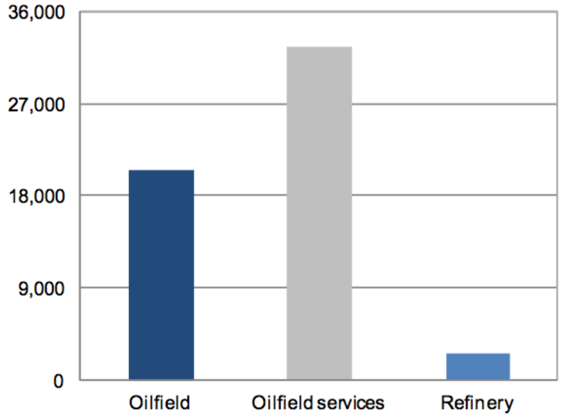
[143] Page 2 – Omar, 1998

## ANNEXURE B



Oil and Gas Supply Chain Services
Indirect Services
• Readily available on the local market
• Offered to other industries
• Less difficult for existing providers to meet standards and specification
• Can be very highly capital intensive
Direct Services
• Services not easily found on the local market
• Requires medium to long term for one to develop skills and expertise to provide them
• Develop skills and expertise for these services through partnership
• Highly capital intensive
Specialists Services
• Complex services required in offshore operations
• Require huge investment with very difficult ease of entry
• Sources of competitive advantage for existing service providers last longer
• Skills and expertise development for services can be attained in the long term
Hotel/Accom.
Fuel
Emergency Services
Communications
Camps/Accom.
IT Services
Medical
Personnel Transport
Marine Gas Oil Supply
Security
Crane Hire
General Trades
Facilities Management
Waste Management
Freight Forwarding
Training
Unskilled Labour
Telecoms
Office Supplies
HR
Catering
Custom Clearance
Environmental Services
Field Construction
Platform Support Vessels
Rig Survey
Marine Survey
Mud/ Cuttings
Infield Services
Mooring Equip.
Inspections
EHS Monitoring Studies
Int. Freight Services
Fixed Wing Services
Infield Transport
Production Chemicals
Lifting Equipments
Tank Cleaning Services
ROV Services
Construction Materials
Rotary Wing
FPSO
Wellhead
Seismic Services
FEED
Well Services
Rig Hire
Subsea Infrastructure
Tangibles

**Potential job creation in industries directly related to exploitation of the oil resource**



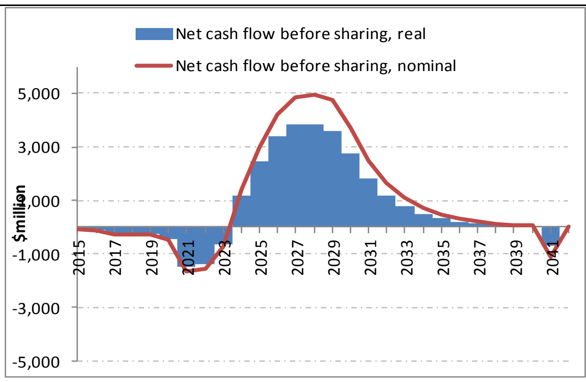

*Sources: Standard Bank Research*

## ANNEXURE C

Project Economics Offshore Oil Fields demonstrating estimated costs over oil & gas life cycle (IMF, 2015:40)_

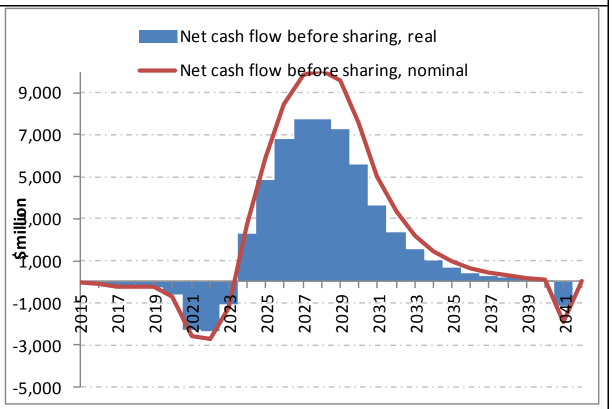
### 500 MmBbl Field

| | | |
|---|---|---|
| Oil Production | 500 | MMbbl |
| Years | 18 | |
| | | |
| *constant 2015 dollars* | $ million | $/Bbl |
| Exploration costs | 980 | 2.0 |
| Development costs | 2,777 | 5.6 |
| Development drilling | 2,859 | 5.7 |
| Operating costs | 4,898 | 9.8 |
| Decommissioning | 662 | 1.3 |
| | 12,176 | 24.4 |




### 1000 MmBbl Field

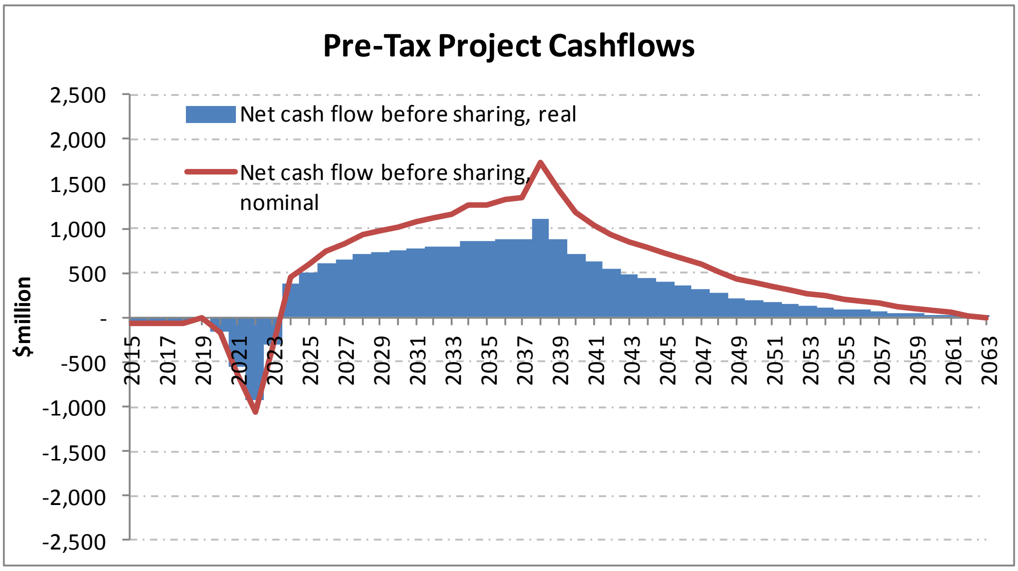
| | | |
|---|---|---|
| Oil Production | 1,000 | MMbbl |
| Years | 18 | |
| | | |
| *constant 2015 dollars* | $ million | $/Bbl |
| Exploration costs | 980 | 1.0 |
| Development costs | 3,888 | 3.9 |
| Development drilling | 6,434 | 6.4 |
| Operating costs | 8,995 | 9.0 |
| Decommissioning | 1,130 | 1.1 |
| | 21,427 | 21.4 |



Project Economics for Shale Gas demonstrating estimated costs over oil & gas life cycle (IMF, 2015:58)

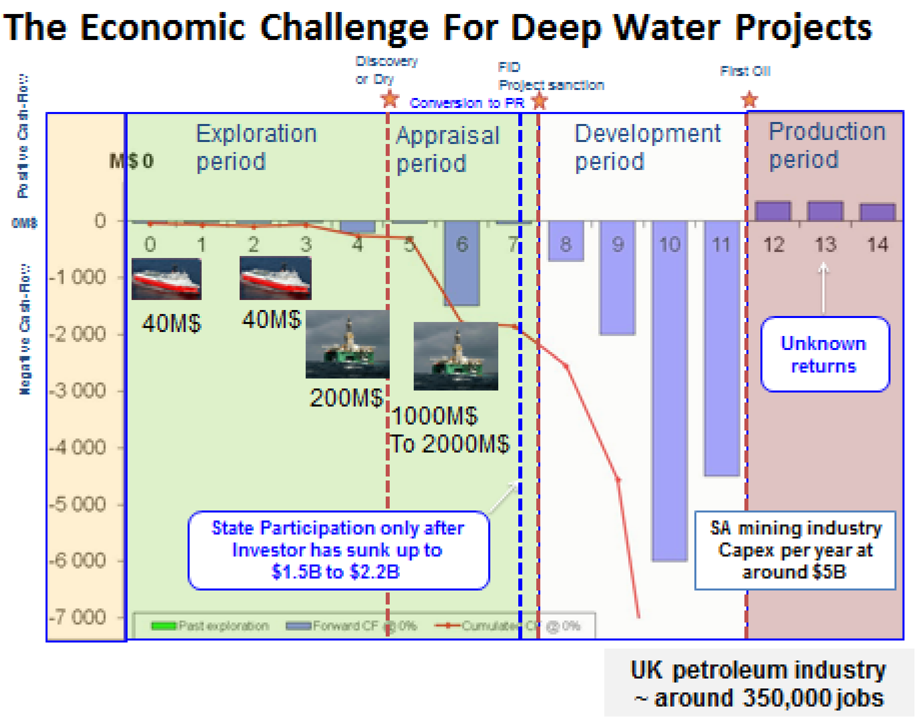
| | | |
|---|---|---|
| Cumulative gas production (reserves) | Tcf | 2,466 |
| Average reserves per well | Bcf | 2.70 |
| Average reserves per well | MMm3 | 76.50 |
| Total wells drilled | wells | 742 |
| Life of project years | years | 43 |
| Exploration costs | US$ million | 106 |
| Development costs, excl. development drilling | US$ million | 584 |
| Development drilling | US$ million | 5,417 |
| Drilling costs per well | US$ million | 7 |
| Operating costs over the project | US$ million | 1,475 |
| Operating costs per Mcf | US$/Mcf | 1.0 |
| Decommissioning costs | US$ million | 98 |
| Total Project Costs | US$ million | 9,455 |
| Average unit cost | US$/Mcf | 3.83 |

*Monetary amounts in 2015 real terms*

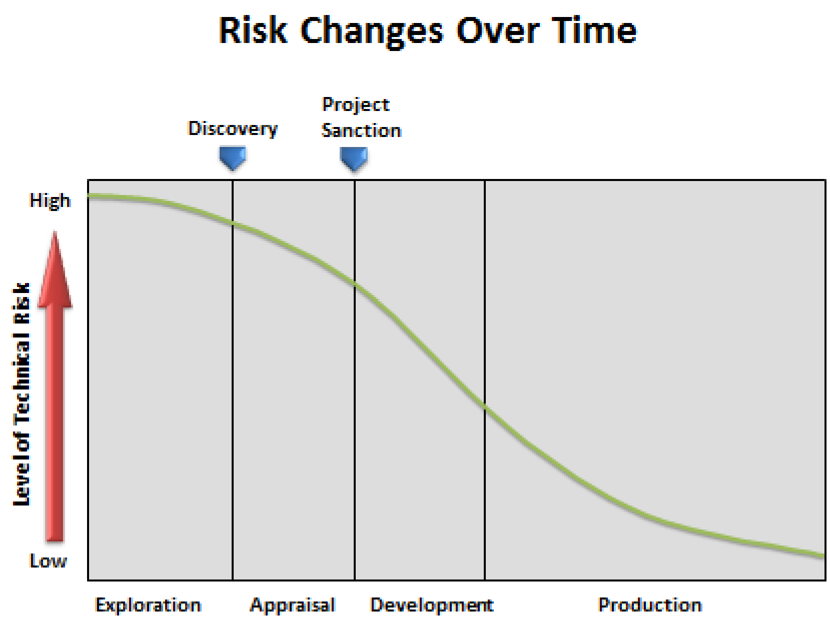


## ANNEXURE D

(Ranosek ,2014:17) The economic challenge for deepwater projects in South Africa




Risk changes over Time (Ranosek, 2014:32)

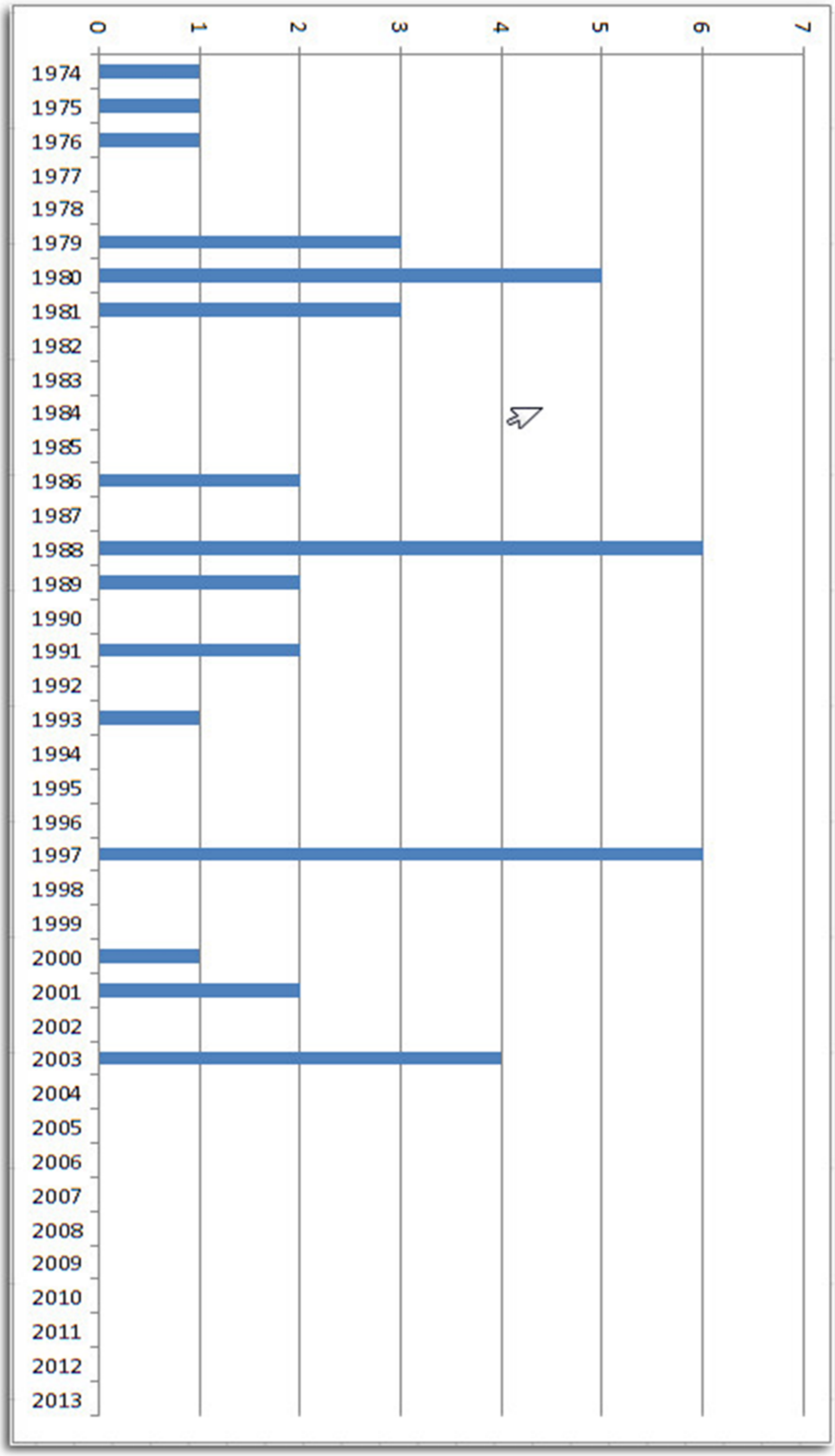


# ANNEXURE E

## Fiscal Regimes

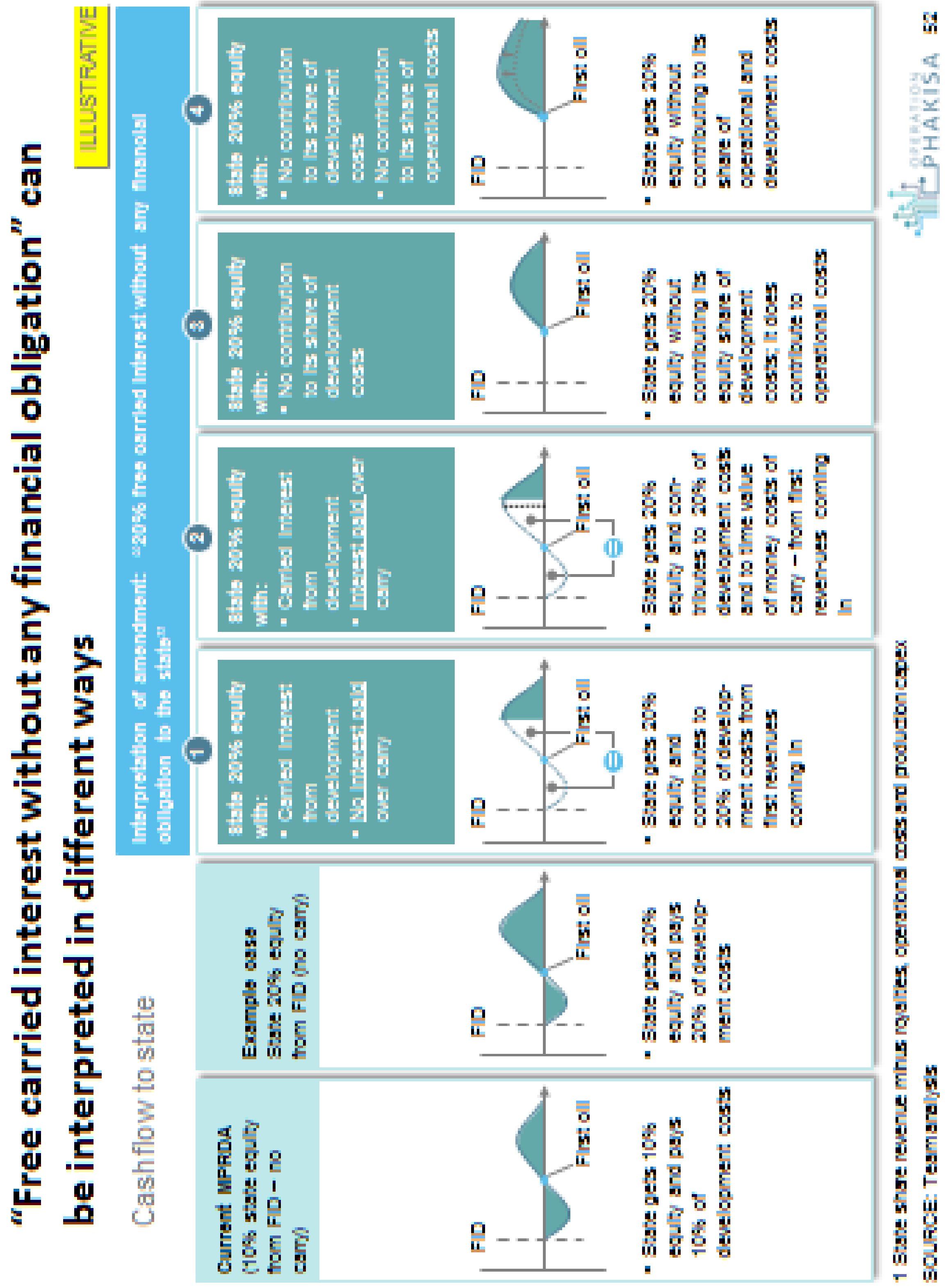
| Country | Royalty | Petroleum Income Tax | Additional Profits Tax | State Participation |
|---|---|---|---|---|
| Algeria | 10-20% | 38% | 5-50% | 51% |
| Angola | 20% | 50-65.7% | | 50% |
| Brazil | 5-10% | 34% | | 30% |
| Cameroon | | 38.5-50% | | 5-25% |
| Chad | 5-10% | 40% | | 25% |
| Cote d'Ivoire | 5-20% | 25% | | 46-60% |
| Ecuador | 12.5% - 18.5% | 81.5-87.5% | | 25% |
| Equatorial Guinea | 13% | 35% | | 20% |
| Gabon | 6-12% | 35-70% | | 66-80% |
| Ghana | 3-12.5% | 35% | 20-25% | 10% free carry +15% participating |
| Indonesia | | 25% | | 15%-25% after 3yrs & 30-35% by end of 5yrs |
| Libya | 16.67% | 65% | | 30-90% |
| Mozambique | 6-10% | 32% | | 5-20% |
| Namibia | 5% | 35% | 20-25% | Carried exploration, contribute from development |
| Pakistan | 12.50% | 40% | | 5-80% based on water depth and production volume |
| Philippines | | 30% | | 60% |
| South Africa | 0.5%-5% | 28% | | 20% |
| Ukraine | Rates according to depth | 21% | | 25% |
| Venezuela | 20-33.3% | 50% | | 50% |

## ANNEXURE F




SA offshore drilling Activity (Ranosek, 2014: 49)

## ANNEXURE G



"Free carried interest without any financial obligation" can be interpreted in different ways
ILLUSTRATIVE
Cashflow to state
Interpretation of amendment: "20% free carried interest without any financial obligation to the state"
Current MPRDA (10% state equity from FID – no carry)
Example case State 20% equity from FID (no carry)
1
State 20% equity with:
Carried interest from development
No interest paid over carry
2
State 20% equity with:
Carried interest from development
Interest paid over carry
3
State 20% equity with:
No contribution to its share of development costs
4
State 20% equity with:
No contribution to its share of development costs
No contribution to its share of operational costs
FID
First oil
State gets 10% equity and pays 10% of development costs
State gets 20% equity and pays 20% of develop-ment costs
State gets 20% equity and contributes to 20% of develop-ment costs from first revenues coming in
State gets 20% equity and con-tributes to 20% of development costs and to time value of money costs of carry – from first reven-ues coming in
State gets 20% equity without contributing its equity share of development costs; it does contribute to operational costs
State gets 20% equity without contributing to its share of operational and development costs
1 State share revenue minus royalties, operational costs and production capex
SOURCE: Team analysis
OPERATION PHAKISA
52

# Depending on the interpretation of "free carried interest" the value to investors can be significantly reduced

Company take · Taxes · Royalties · Equity

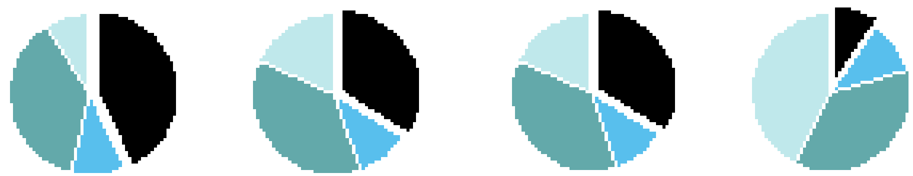
Normalized NPV of company cashflows – success case
Based on example field

| Current MPRDA (10% state equity from FID – no carry) | Example case State 20% equity from FID (no carry) | Interpretation of amendment: "20% free carried interest without any financial obligation to the state" | | | |
|---|---|---|---|---|---|
| | | 1 State 20% equity with: • Carried interest from development • Interest paid over carry | 2 State 20% equity with: • Carried interest from development • No interest paid over carry | 3 State 20% equity with: • No contribution to its share of development costs | 4 State 20% equity with: • No contribution to its share of development costs • No contribution to its share of operational costs |

EXAMPLE RESULTS[2]

— Negative returns —

Capex $30/boe
Opex $15/boe



ILLUSTRATIVE – BEING VALIDATED

1 Interest rate paid over carry in order to compensate losses related to time value of money / inflation
2 Example case is not necessarily representative of the actual cost situation in South Africa deep water offshore

SOURCE: SA regime Cashflow model; team analysis

OPERATION PHAKISA 53

## ANNEXURE H

**Fundamental Legal Designs for Oil and Gas per Country**

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| **Algeria** | Concession | Algeria's fiscal regime is a concessionary system which includes numerous taxes including royalty payments (that range from 5.5% to 23%, surface tax based on per square km, CIT at 38%, petroleum income tax that ranges from 30% to 70% and windfall profits tax that ranges from 5% to 50%. Operators must work in partnership with the national oil company Sonatrach (Entreprise Nationale Sonatrach, which will have at least a 51% participation) and ALNAFT (Agence nationale pour la valorisation des ressources en hydrocarbure, responsible for the promotion, evaluation and concluding of contracts and collecting royalties). There is also a regulatory body ARH (L'Agence Nationale de Contrôle et de Régulation des Activités dans le domaine des Hydrocarbures). |
| **Angola** | Production Sharing Contract | Production sharing contracts are the most common form of contract in Angola. The state concessionaire is Sonangol. PSA and concession holders are not liable to any other Angolan taxes except those relating to petroleum activity. The taxes linked to the petroleum activity are PIT at 50%, Surface fee of USD300 per square km, Training tax contribution of USD0.15 per bbl and Petroleum Production Tax at 20%. Assessment of taxable income is independent (ring-fenced) for each area covered by the PSA except, usually, for exploration expenditure. |
| **Argentina** | Concession | Argentina is organized into federal provincial and municipal governments and the fiscal regime that applies to the petroleum industry is mainly the federal and provincial regime. Federal taxes include income tax (at 35%), VAT (at 21%), minimum presumed income tax (at 1%), personal assets tax (at 0.5%), tax on debits and credits in checking accounts (at 0.6%), custom duties and |

| Country | Fundamental Legal Design | Fiscal Overview |
| --- | --- | --- |
| | | social security taxes (at 23%-27% for employer and 17% for employee). Provincial taxes imposed on the upstream (not downstream) oil industry are turnover tax (averaging at 2.5%), stamp tax (at 1%) and royalties (at 12%). Activities carried out in Tierra del Fuego are exempt from corporate income tax, VAT and Minimum presumed income tax. Local crude prices are regulated by the government and must not exceed $42 per barrel. Export prices are based on WTI less export tax. |
| **Australia** | Concession | The basic structure of petroleum taxation in Australia is a combination of corporate income tax (at 30%) and either a petroleum resource rent tax (PRRT) (at 40%) or a royalty-based tax (that range from 0% to 12.5%). |
| **Azerbaijan** | Production Sharing Contract | The country's tax regime consists of a combination of production sharing agreements (PSAs) and host Government agreements (HGAs), the terms of which have been individually negotiated. A draft law on the fiscal regime has been presented to the Azeri parliament but has not been ratified and it is unknown when it will be. At any rate, the new law would not apply to existing PSAs or HGAs. All exploration and production activities are based on PSAs and are managed by SOCAR while oil and gas pipelines (Baku-Tiblisi-Ceyhan) and the South Caucasus Pipeline are governed by HGAs. Under the PSA's the contractors are subject to a profit tax ( that ranges from 20%-32%) whilst participants in HGAs are subject to a profit tax of 27%. |
| **Bahrain** | Concession | Bahrain's fiscal regime for oil and gas consists of corporate income tax levied at a rate of 46%. |
| **Brazil** | Production Sharing | Brazil's fiscal regime for the oil and gas industry consists of a combination of corporate income tax, Government and some third party takes. |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | Contract | Until 1988, Brazil made use of risk service contracts. Brazil presently uses Production Sharing Contracts. |
| **Cambodia** | Production Sharing Contract | Cambodia's fiscal regime is in the early stages of development and the Petroleum Regulation, 1991 (which was a PSC type) is viewed as out of date   The draft Petroleum Law anticipates PSCs made up of income tax (30%), bonuses, royalties, cost recovery and profit sharing. |
| **Cameroon** | Production Sharing Contract | Cameroon's fiscal regime for the oil and gas industry is impacted by Cameroon's Tax Code, Petroleum Code and the PSC or Concession Agreement. There would appear to be scope for difference in fiscal terms between different PSCs and Concessions. |
| **Canada** | Concession | The fiscal regime is a blend of royalties (10% to 45%) and income taxes.  Both Provincial and Federal authorities are involved.  For 2011 Federal CIT will be 16.5% and Provincial CIT will be 10% in Alberta and BC, 11.5% in the Northwest Territories, 12% in Manitoba and Saskchewan and 14% in Newfoundland & Labrador. |
| **Chad** | Concession | Concessionary system based on royalty (12.5% for oil, 5% gas)), taxes (50% CIT) and bonuses. |
| **China** | Production Sharing Contract | China's fiscal regime is mainly based on PSCs and involves windfall levies when oil prices are above $40 per bbl., royalties (0-12.5%), corporate income tax (25%) and bonuses. |
| **Colombia** | Concession | Colombia's fiscal regime is a combination of corporate income tax and royalty base taxation.  Colombia has fiscal stability contracts |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | to protect investors for 3 to 20 years against adverse changes in laws, regulations and rulings (the cost is 1% of the investment during the year). There are foreign exchange controls (an exemption may be applied for by an oil E&P company or a technical service company working in the area). |
| **Cote d'Ivoire** | Production Sharing Contract | Cote d'Ivoire's fiscal regime is based on PSCs that determine the rate of surface tax rent, bonuses and royalties. Income tax is levied at 25%. |
| **Democratic Republic of Congo** | Concession | The fiscal regime in the Democratic Republic of the Congo (Congo Kinshasa, the former Zaire) is a concessionary one based on royalties and corporate income tax. |
| **Denmark** | Concession | The fiscal regime is a combination of corporate income tax and hydrocarbon tax rates. Hydrocarbon tax rates differ between licences granted before or after January 1, 2004. |
| **Ecuador** | Risk Service Contract | Until August 2010 Ecuador's fiscal regime was a mix of a variety of contracts including joint, shared management and service contracts with a windfall profits tax. In August the government required all PSCs to be re-negotiated into Risk Service Contracts. The government also looks favourably on fee-for-service arrangements. Given the one sided nature of the negotiations some companies left (e.g. Petrobras and Noble) while others (e.g. Repsol) decided to stay even though the expected share of the government's take will move from 70% to 80%. |
| **Egypt** | Production Sharing Contract | Egypt's fiscal regime comprises income (40.55%) and royalty (10%) based taxation. The Petroleum Concession Agreement signed with the Egyptian Petroleum Corporation (EGPC) is the basic |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | document used. Subject to foreign exchange shortages, there is no restriction on repatriation of profits. |
| **Equatorial Guinea** | Production Sharing Contract | The fiscal regime is a mixture of royalties (minimum 13% escalating with volume), corporate income tax (35%) plus bonuses, surface rents and share of profit oil stipulated in the PSC. The tax code of October 28, 2004 and the Hydrocarbon law Number 8/2006 of November 3, 2006 apply. |
| **Ethiopia** | Production Sharing Contract | Ethiopia uses a model production sharing agreement or a concession contract between the government (represented by the Minister of Mines) and the contractor. Royalties, surface rents, income tax and bonuses are the prime components of the system. |
| **Falkland Islands** | Concession | The Falklands fiscal system comprises a variable acreage rental; a 9% royalty on production and a 26% corporation tax on profits. |
| **Gabon** | Concession | The fiscal regime comprises corporate taxation (35% to 73%), annual surface rents, signature and production bonuses, and royalties (6% to 12%) on production. |
| **Ghana** | Concession | Ghana operates a royalty/tax fiscal regime. The Internal Revenue Act (IRA, which applies mainly to downstream activities), the Petroleum Income Tax Law (PITL, under review) and the Petroleum Agreement (PA) apply. The PA is usually an agreement between the oil company and the Ghana National Petroleum Company (GNPC) and the Ghana government (GOG). With the discovery of commercial quantities of oil, the incentive for GOG to tighten contracts and conditions has increased. |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| **Greenland** | Concession | Greenland's fiscal regime is a concessionary system involving corporate income tax (on income (30%) and dividends (up to 37% WHT)) and royalties (not currently levied). |
| **India** | Production Sharing Contract | India's fiscal system is a hybrid one of Production Sharing Contracts with the government and aspects of royalty payments, cost recovery and CIT. A new Direct Tax Law came into operation April 1, 2012. |
| **Indonesia** | Production Sharing Contract | Indonesia mainly uses production sharing contracts for its fiscal regime. This involves a first tranche payment of petroleum (FTP), bonuses, cost recovery, profit sharing, income taxes and domestic market obligations (DMO). |
| **Iran** | Buy back Service Contract | Iran's fiscal regime is based on service contracts involving cost recovery and a remuneration fee. |
| **Iraq** | Risk Service Contract | The Iraqi fiscal regime involves technical service contracts. These involve signature bonuses, cost recovery, supplementary cost, remunerations fee and corporate income tax. The Regional Government of Kurdistan has issued PSCs and discussion whether these must be converted to service agreements is currently ongoing. |
| **Ireland** | Concession | Ireland's fiscal regime consists of a combination of corporate income tax (25%) and petroleum resource rent tax (PRRT) (5%-15%). |
| **Ivory Coast** | Hybrid – PSC & Risk Service Contract | The fiscal system is a not standard mix CIT (25%), royalties, bonuses, surface rents and additional petroleum taxes contained in the PSC or Service Contract. The Ivorian tax law and petroleum code |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | apply. Different fiscal regimes apply to Exploration and Production (E&P) companies versus Petroleum Service Contractors. |
| **Kazakhstan** | Concession | A new regime was introduced from January 1, 2010. Prior PSCs and contracts specifically approved by the President may have different rules. The current regime is a blend of corporate income tax (20% reducing to 15% in 2014), rent tax on exports (around 17%), bonuses and royalty-type taxation (a MET of 5 to 18%) plus a $20 per ton export duty and an excess profits tax. Higher oil and mining taxes will compensate for the lower CIT planned. |
| **Kenya** | Production Sharing Contract | The fiscal regime in Kenya is production sharing system. The main elements are income tax, profit sharing and cost recovery. No oil has yet been discovered in Kenya. |
| **Kuwait** | Concession | Kuwait's fiscal system does not differentiate oil and gas companies from other foreign companies. Taxes consist of CIT (15%) and royalties (15%) |
| **Libya** | Production Sharing Contract | The Libyan fiscal regime is based on PSCs involving CIT and a surtax designed to tax profits at the 65% rate. Taxes are paid through the national oil company. The Libyan Dinar is not a convertible currency. |
| **Madagascar** | Production Sharing Contract | The fiscal regime in Madagascar is mainly based on PSCs (joint ventures are permitted) and includes royalty, cost recovery, profit sharing and income tax. |
| **Malaysia** | Production Sharing | The fiscal regime is a blend of a petroleum income tax (38%) and royalties (10%). Income |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | Contract | from upstream petroleum operations falls under the Petroleum (Income Tax) Act PITA. |
| **Mexico** | Concession | Mexico’s fiscal system has no special rules applicable to oil and gas companies. CIT is temporarily levied at 30% for the period 2010-2012. The tax rate is reduced to 29% for 2013 and goes back to 28% for 2014 and subsequent years. |
| **Mozambique** | Production Sharing Contract | The fiscal regime comprises royalties (2% to 10%), fees (at least $50,000 per contract) and corporate income tax (32% on worldwide income). Oil operations are based on Production Sharing Contracts. There are strict foreign exchange control regulations in force. |
| **Namibia** | Concession | Namibia’s fiscal regime is a mixture of a Petroleum Income Tax (35%) under the Petroleum (Taxation) Act 3 of 1991 (the PTA), administrative provisions of the Income Tax Act 24 of 1981, (e.g. an additional profits tax of at least 15%), royalties (5%) levied on sales under the Petroleum (Exploration and Production) Act 2 of 1991 and registration fees (US$ 9 per sq. km. licence block for the first 4 years, increasing thereafter). |
| **Netherlands** | Concession | The fiscal regime comprises corporate income tax (25.5% over €200,000 ($US 267,000)), a surface rental tax ($930 per sq. km. for production areas), a 50% state profit share (SPS) and royalty (0% to 7%) based taxation. |
| **New Zealand** | Concession | A combination of Corporate Income Tax (30%) and royalty based taxation (usually 5% of value or 20% of profits) is used in the fiscal regime. |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| **Nigeria** | Hybrid – PSC & Concession | In Q4 2011 the government was still struggling to introduce a new Petroleum Industry Bill into law. Consequently details provided here are subject to change. At present both concessionary and petroleum sharing agreements are used. Companies carrying on petroleum operations are deemed to be in the upstream regime (and exclude refining) and taxed under the Petroleum Profits Tax Act (PPTA) 2004 as amended. Nigeria operates both a licensing regime (joint ventures with the Federal Government or sole risk operator) and contractual regimes (risk service contracts or production sharing contracts). PSCs have been used most frequently in Nigeria. Risk Service Operators are treated as not carrying out petroleum operations but rather on performance contracts and paid as service providers (taxable at the lower rates of the Companies Income Tax Act rather than the PPTA. Under all arrangements the Federal Government operates through the Nigerian National Petroleum Company (NNPC). |
| **Norway** | Concession | Upstream operations attract both a CIT of 28% plus a special tax of 50% along with surface fees (starting at US$5,146 per sq. km.). |
| **Oman** | Production Sharing Contract | The main part of the fiscal regime is corporate income tax (55%), and are combined with surface fees and bonuses described in the Production Sharing Contract. |
| **Pakistan** | Production Sharing Contract | Onshore operations have petroleum concession arrangements while PSCs are used for offshore. There is a blend of Corporate Income tax (40%), a windfall levy (roughly $20 per bbl at an oil price of $80), royalty payments (12.5%), surface rents and bonuses in the fiscal regime. |

| Country | Fundamental Legal Design | Fiscal Overview |
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| **Papua New Guinea** | Concession | PNG's fiscal regime is a mix of income tax, royalties and development levies, additional profits tax and infrastructure tax credits. A tax clearance certificate is required to remit more than PGK 200,000 (about US$78,000) during a year. |
| **Peru** | Hybrid – PSC & Risk Service Contract | The fiscal regime in Peru for oil and gas exploration and production is set under licences or service contracts with the Government. The Government guarantees that the tax law will not change over the life of the contract. |
| **Philippines** | Risk Service Contract | Philippines fiscal regime is a combination of CIT and service contract. The service contractor receives its share of petroleum as service fee equivalent to 40% of the net proceeds from the petroleum operations. The service contractor is subject to CIT at a rate of 30%. |
| **Poland** | Concession | The basis of Poland's fiscal regime is a concessionary system involving surface rental and concession fees, royalty and corporate income tax payments. |
| **Qatar** | Production Sharing Contract | Qatar's fiscal system is a PSC. PSC's concluded from 1 Jan 2010 provide for CIT at 35%. PSC's entered into prior to this date still apply and in accordance with the PSC are taxed at rates ranging from 35%-55%. The royalty rate is negotiated in the PSC. |
| **Republic of Congo** | Production Sharing Contract | The fiscal system in the Republic of the Congo (Congo Brazzaville) is one of PSCs, comprising cost recovery and profit sharing. |
| **Romania** | Concession | The fiscal regime consists of CIT, royalty and |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | resource rent tax. |
| **Russia** | Concession | The fiscal regime is a blend of corporate profits tax (20%), mineral extraction tax (roughly 22% of the value of production in excess $15 per bbl.) and export duty (35 to 65%, with Urals at $88, the duty is $45 per bbl.). |
| **Saudi Arabia** | Concession | Saudi Arabia's fiscal regime is a combination of corporate income tax (85%) and royalties (as determined by the petroleum concession agreement). |
| **Senegal** | Hybrid – PSC & Concession | A mixture of Corporate Tax (35%), Annual Surface Rent, Royalty (2-10%) and Additional Petroleum Tax comprise Senegal's fiscal regime. Both concessions and PSCs are used. |
| **Singapore** | Concession | There is no separate tax regime for oil and gas companies. CIT is levied at 17%. |
| **South Africa** | Concession | South Africa's fiscal regime comprises a combination of corporate income tax (28%) and royalties determined in accordance with a formula (0.5%-5%) based on EBITA. |
| **Spain** | Concession | Spain's fiscal system consists of a combination of corporate income tax with some special rules and surface tax. |
| **Syria** | Production Sharing Contract | A production sharing contract is entered into with GPC (as representative for the Syrian government). Corporate Income Tax is charge in accordance with a sliding scale based on profits ranging from 10%-28%. The royalty rate is determined by the PSC. |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| **Sudan** | Production Sharing Contract | Sudan’s fiscal regime is based on PSCs, including royalty, cost recovery and profit sharing |
| **Tanzania** | Production Sharing Contract | Tanzania’s fiscal regime includes CIT (30%), royalties (12.5% Onshore, 5% Offshore) and, potentially, additional petroleum tax (25% or 35% not yet introduced). |
| **Thailand** | Production Sharing Contracts | There are 3 different fiscal regimes. The regimes are designated Thailand I (mainly projects prior to 1982), Thailand II (projects awarded 1982 to August 13, 1986), and Thailand III (projects awarded after August 14, 1986). Each regime has different benefit sharing structures. The regimes incorporate petroleum income tax, PSC and royalties along with an annual bonus (under Thailand II) and special remuneration benefits (under Thailand III). |
| **Trinidad and Tobago** | Hybrid – PSC & Concession | Either PSCs or Exploration and Production Licences are used. There is a separate fiscal regime for upstream oil companies governed by the Petroleum Taxes Act. This sets out a profits tax, a supplemental petroleum tax, a petroleum production levy, a petroleum impost, royalties, unemployment levy and green fund levy. |
| **Tunisia** | Hybrid – PSC & Concession | Tunisia’s fiscal regime is based on both PSCs (cost recovery and profit sharing) and Concessions (royalties and income taxation). Companies work in partnership with ETAP. |
| **Uganda** | Production Sharing Contract | As a new producer (oil expected in 2011) Uganda’s fiscal arrangements are in transition and a new Petroleum Bill is before parliament. The fiscal regime is a blend of income tax (30%), production sharing agreements with the government, bonuses, |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | surface fees and royalty (5% to 12.5%) based taxation. |
| **United Kingdom** | Concession | The UK fiscal regime is a concessionary one involving corporate income taxes (26%) and supplementary charges (20%). A petroleum revenue tax of 50% applies to pre March 16,1963 concessions, but not subsequent ones. |
| **United States** | Concession | The U.S. fiscal regime is a combination of corporate income tax (35%), severance tax (to the States various rates) and royalty payments (12.5% to 30% Onshore, 18.75% Offshore). Onshore mineral rights may be held by the Federal government (managed through the Department of the Interior's Bureau of Land Management or Department of Agriculture's Forest Service), States, Indian reservations, individuals, corporations, trusts etc. Offshore mineral interests are originally owned by the Federal government (managed by the Department of the Interior's Mineral Management Service (MMS). There is a foreign investment review board. |
| **Uzbekistan** | Production Sharing Contracts | The fiscal regime that applies to production sharing contracts in Uzbekistan consists of a combination of corporate income tax, bonuses, subsurface use tax and excess profits tax (EPT). |
| **Venezuela** | Joint Venture | The fiscal regime is based on a mixture of corporate income tax, royalty payments, indirect taxes and special contributions. According to law, upstream activities are reserved for the Venezuelan State operating directly or via state owned enterprises (e.g. Petróleos de Venezuela, S.A. (PDVSA)). Joint venture corporations (Empresas Mixtas) in which the State owns at least 50% are used and are subject to approval of the National Assembly which also sets the |

| Country | Fundamental Legal Design | Fiscal Overview |
|---|---|---|
| | | conditions of operation. |
| **Vietnam** | Production Sharing Contract | The Petroleum Law and other tax regulations provide the outline of the fiscal regime. The main features are a CIT of 50% (32% for encouraged projects), a royalty between 6 and 40% and an export tax between 5% and 50%. PSCs (in accordance with the model contract) between foreign oil companies and Vietnam Oil and Gas Group (Petrovietnam) are the means of operation. |
| **Yemen** | Production Sharing Contract | Yemen's fiscal regime is based on PSCs with royalty payments, cost recovery and profit sharing being the main components. |

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